JOINT DIRECT TESTIMONY OF
DEREK P. STENCLIK
ON BEHALF OF
SIERRA CLUB, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE,
AND SOUTHERN ALLIANCE FOR CLEAN ENERGY
DOCKET NO. 2023-E-9

INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, position, and business address for the record

A: My name is Derek Stenclik and I am the President of Telos Energy, Inc. My business address is 475 Broadway, Unit 6, Saratoga Springs, NY 12866.

Q: Please summarize your professional and educational qualifications.

A: I am the founding partner of Telos Energy, Inc., an analytics and engineering firm specializing in grid planning, renewable integration, and resource adequacy. I have a decade of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration.

I specialize in production cost and resource adequacy modeling for grid planning, asset development, wind and solar integration, and battery energy storage. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models and resource adequacy models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the PLEXOS, GE MAPS, and SERVM models, and have reviewed input and output data for several other industry models.

I am also involved in many industry groups and forums, including at the Institute of Electrical and Electronics Engineers (IEEE), International Council on

Large Electric Systems (CIGRE), and Energy Systems Integration Group (ESIG). Currently I am leading the ESIG Working Group on Redefining Resource Adequacy, which is considering novel ways to improve resource adequacy analysis and reliability planning during the power sector's transition. I am also currently participating on the Technical Advisory Panel for the Hawaiian Electric Company's Integrated Grid Planning efforts.

From 2011 to 2018, I was employed by GE Energy Consulting, most recently as the Senior Manager of Power Systems Strategy. In that role I was responsible for a team of engineers and economists that conducted economic and transmission planning studies for utilities, grid operators, and developers across North America.

I hold a master's degree in Applied Economics and Management from Cornell University and graduated with Summa Cum Laude and Phi Beta Kappa honors from State University of New York, College at Geneseo. Additional qualifications are included in my current resume, attached as Exhibit DS-01.

Q: Have you previously testified as an expert witness before the Public Service Commission of South Carolina (the "Commission") or before other regulatory bodies?

A: Yes, I filed expert testimony and appeared before the Public Service Commission of South Carolina in Dominion Energy South Carolina's 2019 Avoided Cost Proceeding (Docket No. 2019-184-E) on behalf of The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy and I provided direct testimony in the DESC 2020 Integrated Resource Plan (Docket No. 2019-

226-E) on behalf of the Sierra Club. In addition, I also provided written comments on behalf of the Sierra Club for the DESC 2021 Integrated Resource Plan (Docket No. 2021-9-E), the DESC 2022 Coal Retirement Study (Docket No. 2021-192-E), and the DESC 2022 Integrated Resource Plan Update (Docket No. 2022-9-E). Over the past two years I have also regularly engaged in the DESC IRP Stakeholder Meetings.

In addition to proceedings in South Carolina, I have also provided expert testimony in Colorado regarding Public Service Company of Colorado's 2021 Electric Resource Plan. I also supported testimony for the New Mexico Public Regulation Commission and regularly testify in proceedings with the Hawaii Public Utilities Commission.

Q: Do you have recent experience evaluating resource plans for utilities considering coal retirements in other jurisdictions?

A: Yes. In the past few years I have provided technical analysis and modeling related to three coal retirement decisions, all of which were presented to state regulators. One analysis evaluated the reliability implications of retiring a coal plant in Hawaii and replacing it with hybrid solar+storage plants,[1] and a second analysis evaluated alternative replacement portfolios to the San Juan coal retirement in New Mexico.[2] Both of these coal plants were retired in September 2022. I also provided analysis and testimony for the Craig, Comanche, and Pawnee coal plant retirements in

[1] Work conducted for ongoing engagement with the Hawaii Natural Energy Institute, in collaboration with the Hawaii Public Utilities Commission and Hawaiian Electric Company. https://www.hnei.hawaii.edu/projects#GI.

[2] Direct Testimony of Michael Milligan, "Public Service Company of New Replacement for San Juan Generating Station," Case No. 19-00195, December 13, 2019.

Colorado. All of this work showed that coal plants can be reliably retired using a portfolio of clean energy resources.

Q: On whose behalf are you testifying in this proceeding?

A: I am submitting this testimony on behalf of the Sierra Club, Southern Alliance for Clean Energy and the South Carolina Coastal Conservation League (collectively, "Nonprofit Intervenors").

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

Table 1. Sponsored Exhibits

Exhibit Number	Description of Exhibit	Confidential or Non-Confidential
Exhibit DS-01	Resume of Derek Stenclik	Non-Confidential
Exhibit DS-02	DESC Response to ORS 1-26	Non-Confidential
Exhibit DS-03	Sierra Club comments submitted to IRP Stakeholder Session VII Homework	Non-Confidential
Exhibit DS-04	DESC Response to ORS 2-11	Non-Confidential
Exhibit DS-05	Sierra Club comments to IRP Stakeholder Session VIII	Non-Confidential
Exhibit DS-06	DESC CONFIDENTIAL response to Sierra Club 1-3	Confidential
Exhibit DS-07	DESC response to Sierra Club 3-3	Non-Confidential
Exhibit DS-08	DESC response to ORS 1-55	Non-Confidential
Exhibit DS-09	DESC Response to Sierra Club 2-1	Non-Confidential
Exhibit DS-10	CCL/SACE and Sierra Club CONFIDENTIAL comments submitted in response to DESC Stakeholder Session X	Confidential
Exhibit DS-11	DESC response to Sierra Club 1-5	Non-Confidential

Exhibit DS-12	DESC response to Sierra Club 3-5	Non-Confidential
Exhibit DS-13	DESC CONFIDENTIAL response to ORS 1-10	Confidential
Exhibit DS-14	DESC response to Sierra Club 1-6	Non-Confidential
Exhibit DS-15	DESC response to Sierra Club 3-4	Non-Confidential
Exhibit DS-16	Build Plan Tables	Non-Confidential
Exhibit DS-17	DESC response to SACE/CCL 1-4	Non-Confidential

Q: What is the purpose of your direct testimony in this proceeding?

A: The purpose of my direct testimony is to review and evaluate various components of Dominion Energy South Carolina ("DESC" or "the Company") 2023 Integrated Resource Plan (IRP). I first highlight some of the major reservations in DESC's IRP, then discuss alternative assumptions that should be used in DESC's long-term planning. In addition, I identify risks embedded in DESC's preferred plan, and present modeling results for alternative resource plans to the ones proposed by DESC. Finally, my testimony recommends that the Commission take actionable steps to retire coal generation and replace it with modern, clean, and flexible technologies.

Q: Please identify the documents and filings on which you base your opinions regarding DESC's 2020 IRP.

A: In addition to the Company's IRP and related appendices and supporting documents, I reviewed DESC's responses to discovery filed by Office of Regulatory Staff and other intervening parties. I also reviewed the NREL Annual Technology Baseline (ATB), a number of industry publications, news articles and press releases.

Q: How is the remainder of your testimony organized?

A: My testimony is organized into six sections, outlined below:

I. Summary of Testimony and Key Conclusions
II. Notable issues with DESC's IRP assumptions and methods
III. Risks associated with DESC's preferred plan
IV. Independent modeling of alternative portfolios
V. Reliability considerations of alternative portfolios
VI. Recommendations for the Commission and the Company

I. SUMMARY OF TESTIMONY AND KEY CONCLUSIONS

Q: Can you provide a brief summary of your main findings?

A: My testimony outlines portions of the 2023 DESC IRP that the Commission should support, while also recommending several important changes to inputs and assumptions. Overall, I am concerned that DESC has yet again failed to adequately evaluate a non-fossil fuel replacement portfolio for the Williams and Wateree retirements, and is instead over-committing to a portfolio where nearly 60% of the annual energy comes from gas resources. Alternative portfolios without fossil fuel replacement resources for Williams and Wateree could yield cost savings for DESC ratepayers, improve reliability, reduce pollution and improve human health, and reduce gas to 40% of the overall generation mix.

When combined with new Inflation Reduction Act ("IRA") subsidies and incentives, a portfolio that further leverages solar and storage additions would have lower cost and emissions relative to the portfolios evaluated by DESC. In addition, if strategically located, this portfolio could avoid or mitigate the transmission and gas infrastructure upgrades necessary for DESC's proposed capacity additions. This would allow replacement portfolios to be in service sooner and avoid unnecessary Effluent Limitation Guidelines ("ELGs") retrofits at the existing coal plants, saving ratepayers an additional $90 million. As a result, the alternative portfolios outlined in my testimony represent the most reasonable and prudent options for DESC.

To illustrate and quantify these points, my testimony in this proceeding includes detailed modeling and simulations to reinforce how a portfolio that does not add new gas resources can reduce cost. These findings are discussed further in Section 4. Through a detailed review of the 2023 DESC IRP and independent modeling results, I make the following conclusions regarding DESC's analysis and preferred portfolio.

In addition, the following table respectfully provides a list of the highest-priority, actionable recommendations for both the Commission and DESC to improve in this IRP. In Table 2, I also note whether or not these recommendations were made in the 2022 IRP Update comments.[3]

Table 2. Highest Priority Recommendations for the 2023 IRP

	Recommendations	Identified in 2022 DESC IRP Update Comments or Stakeholder Sessions?
1	Evaluate at least one non-fossil fuel coal replacement portfolio that does not include new gas resources to replace the Williams and Wateree coal plants.	YES

[3] Docket No. 2022-9-E, Sierra Club Comments on 2022 IRP Update at XX (Jan. 19, 2023).

2	Properly incorporate IRA energy community bonus credits for standalone battery storage and some of the potential solar PV additions.	YES
3	Remove the arbitrary 50/50 utility self-build and PPA solar resource ratio and use whichever resource candidate is lower cost.	N/A
4	Increase annual build limits for solar resources and make storage resources available earlier in the model horizon.	YES
5	Fix the heat rate for new gas resources to reflect higher heating value (HHV) rather than lower heating value (LHV)	YES
6	Properly assign the TIA transmission upgrade costs based on new gas builds rather than on the coal retirement decision.	YES
7	Adjust errors in the battery FO&M and weighted average cost of capital that were identified in the IRP.	N/A

Q: In your opinion, does the modeling performed by DESC in its 2023 IRP result in reasonable future resource plans?

A: No, it does not. DESC's preferred resource plan ("Reference Build Plan") is based on inappropriate assumptions, including arbitrary limits on annual solar builds, limitations placed on battery storage as a capacity resource, transmission costs that are misapplied, new gas heat rates that are unrealistic, and a failure to fully benefit from federal subsidies available under the IRA. This resulted in 60% gas portfolios that have limited fuel diversity, rely heavily on new gas resources, artificially limit lower cost and lower risk renewable energy, and fail to capitalize on available federal subsidies which would lower costs for DESC ratepayers.

My independent modeling indicates that when assumptions are revised to more realistic values, DESC's preferred plan is not economically competitive as compared to alternatives that further deploy solar and storage resources which would help balance DESC's already large reliance on natural gas. Based on this analysis, DESC should retire Wateree and Williams by 2028, avoid unnecessary capital expenditures, operations and maintenance costs, ELG costs, and transmission upgrade costs. Instead, DESC should plan for additional solar and storage resources that can lower overall costs and be strategically located to improve reliability and avoid new transmission and unnecessary gas pipelines. Compared to DESC's preferred portfolio, doing so would save DESC ratepayers anywhere from $4.7 million to $62 million, compared to DESC's preferred portfolio depending on the alternative portfolio selected and the amount of potential deferred transmission upgrades.

II. NOTABLE ISSUES WITH DESC'S IRP ASSUMPTIONS AND METHODS

Q: Before discussing your concerns, were there any notable improvements to DESC's 2023 IRP compared to its 2020 IRP?

A: Yes. I would like to take a moment to highlight notable improvements to the 2023 DESC IRP when compared to the last full IRP in 2020. First and foremost, this is the first IRP that benefited from the IRP Stakeholder Group and the first IRP that benefited from optimized expansion planning in PLEXOS. I would like to acknowledge the effort of the Company over the past year to engage with stakeholders in this forum, provide data and assumptions early in the IRP process, and listen to feedback. The transparency afforded to intervenors in that process ensures that the Company's planning receives the third-party review necessary for robust, accurate, and high-quality resource planning. To improve the stakeholder process further, I recommend that DESC specifically track stakeholder comments that were acted upon in the final IRP, even if the Company does not agree with the assumptions or its findings. This would ensure that stakeholder feedback is being not only listened to, but also acted upon.

I would also like to highlight the improvement in DESC's development of the Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC) assumptions for the 2023 IRP, as presented in the DESC 2023 Planning Reserve Margin Study ("PRM and ELCC Study"). These are important assumptions for an IRP because they have an effect on reliability and cost of the whole DESC system. In previous comments, I identified a need for a more robust, probabilistic framework, to develop PRM and ELCC assumptions that capture the synergistic, portfolio benefits and saturation effects that occur for all resources, but specifically for solar and storage.[4]

In this IRP, DESC contracted with Astrapé Consulting to conduct a probabilistic loss of load expectation (LOLE) study to determine the PRM and ELCC used in subsequent analysis. While I do not agree with all the assumptions used in the Astrapé analysis, this overall approach[5] is a useful way to determine the reliability contributions of various resources. In future iterations of this analysis, I recommend that the ELCC framework be applied to all resources in a consistent manner, which I discuss further in Section 5.

Q: Did DESC use any specific assumptions that you agree with and would like to highlight for the Commission?

[4] Docket No. 2019-226-E, Sierra Club Comments to DESC's 2020 Integrated Resource Plan at 37 (Jul. 10, 2020).

[5] The methodology employed a sequential, Monte Carlo, loss of load analysis evaluating resource adequacy across various weather years, different generator outage draws, captured the benefits of solar and storage added in conjunction with one another, and considered availability of imports from neighboring utilities during tight supply conditions.

A: Yes. First and foremost, I agree with DESC's continued acknowledgement that accelerated coal retirements are in the best interest of South Carolinians and DESC ratepayers. This has been a consistent finding since the 2020 Modified IRP and was reiterated in the Company's 2021 IRP Update, the 2022 Coal Retirements Study, and the 2022 IRP Update. As DESC stated in the 2021 IRP Update and the Coal Retirement Study, "DESC's current goal is to end reliance on coal as a fuel source by 2030 assuming that goal can be achieved consistent with maintaining reliability and reasonably priced service to its customers"[6] and that "[t]he modeling . . . shows that early retirement of Williams remains a lower cost option than continuing to operate it until the end of its useful life."[7]

DESC's commitment to pursue coal retirements in its long-term plan should be applauded. However, while this finding has been consistent for three years, there have been no definitive commitments from DESC on the timing of its coal retirements or definitive actions to bring on replacement resources. DESC continues to make assertions that "the 2022 Coal Plants Retirement Study found it was impracticable to retire and replace Williams before December 31, 2030, at the earliest,"[8] and has identified new transmission upgrades and gas pipelines to be the longest lead time for those retirements, but has not taken meaningful steps to select replacement resources *for over three years*, nor have they evaluated resource portfolios that may obviate the need for long lead-time transmission and natural gas

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[6] Docket No. 2021-192-E, DESC Coal Retirement Study at 3.
[7] DESC 2023 IRP at 7.
[8] Ibid.

upgrades. In other words, it is DESC's own inaction that is making it infeasible to retire and replace coal units before 2030.

Q: Besides DESC's preference to accelerate coal retirements, are there any other assumptions that you agree with and want to highlight with the Commission?

A: Yes. I would also like to acknowledge DESC's continued use of a CO_2 price in its Reference Scenario modeling. I agree with DESC that inclusion of a CO_2 price in the IRP modeling scenarios is warranted for two reasons. First and foremost, there are real damages attributed to CO_2 emissions and including a carbon price in the analysis captures some—though certainly not all—of the social cost of carbon that should be considered by system planners.

Secondly, I agree with DESC that a CO_2 price serves as a valuable proxy for future environmental regulations that are not only possible, but probable, at the federal or state level. While we may not know specifics of these future environmental regulations, a CO_2 price serves as a useful proxy to reflect this uncertainty. For instance, as I discuss further in Section 3, EPA recently proposed a greenhouse gas rule that would impose strict requirements on coal plants operating past 2035 and on new and existing gas plants starting in 2032, both of which would require substantial capital investments.[9]

As DESC stated in its response to ORS discovery, "[t]he IRP models zero CO_2 cost, medium CO_2 cost and high CO_2 cost to comply with the requirements of Act No. 62. While there is currently no explicit price on CO_2 and the design of

[9] U.S. Environmental Protection Agency, *NSPS for GHG Emissions from New, Modified, and Reconstructed Electric Utility Generating Units*, https://www.epa.gov/stationary-sources-air-pollution/nsps-ghg-emissions-new-modified-and-reconstructed-electric-utility

future policies is uncertain, the medium level of CO_2 assumes that a moderate CO_2 price is imposed on the electric sector as a proxy for future policy that increases the cost of fossil-fired resources."[10]

This evaluation has important implications for the DESC Reference Build portfolio. As DESC Witness Best stated in her direct testimony:

> [t]he only build plan that is comparable in terms of cost considerations under any of the three Core Market Scenarios is the Zero Carbon Cost Build Plan, which only out-performs the Reference Build Plan as to cost or regrets under the assumption that carbon emissions remain cost free for the duration of the planning period. This is not an assumption on which DESC believes it should base its generation planning at this time.[11]

DESC and Nonprofit Intervenors thus seem to agree that the Commission should focus its review on build plans that include a CO_2 cost and consider the likelihood of future environmental regulations in its decisions.

Q: Turning to your concerns with DESC's IRP, are there any methodological flaws or problems in the IRP that you would like to discuss?

A: Yes. Perhaps the most important flaw in the DESC 2023 IRP is DESC's continued reluctance to include a non-fossil fuel *coal replacement* portfolio in its analysis. Since the 2019 IRP, myself and other stakeholders have been resolute in our request for DESC to include at least one portfolio in its analysis that would rely on existing gas resources plus new non-fossil fuel resources for the replacement of the Wateree and Williams coal plants. In the 2022 IRP Update comments, we stated that "this is a top priority request for multiple stakeholders and has not been evaluated by

[10] DESC Response to ORS 1-26 at 2, attached as Exhibit DS-02.
[11] 2023 DESC Integrated Resource Plan at 76; Direct of Betty Best at 23.

DESC despite multiple requests and independent modeling identifying it as a least cost pathway."[12] As shown below, stakeholders shared these concerns with DESC multiple times and in multiple forums:

- In Sierra Club's 2019 IRP testimony, I conducted independent modeling which showed that "[a]s the tables and figures indicate, the coal retirement scenarios with a replacement of solar and storage are the least cost options for DESC ratepayers, as compared to DESC's [preferred] RP2 portfolio." In addition, I recommended that the Commission and DESC "consider alternative portfolios for DESC's IRP, specifically ones that retire the Williams and Wateree coal plants and replace them with clean modern, and cost-effective technologies."[13]
- CCL/SACE and CCEBA recommended in Comments on the 2021 IRP Update that "DESC should work with stakeholders to prepare a new variation of the RP8 portfolio—referred to herein as RP8b—that retires Wateree and Williams in 2028 and replaces them with clean energy resources. This analysis should be conducted prior to the proceedings in DESC's coal retirement docket."[14]
- In the 2021 IRP comments, Sierra Club stated, "Recommendation #1: DESC should evaluate a new resource plan that includes a full and partial

[12] Docket No. 2022-9-E, Sierra Club Comments to 2022 IRP Update at 11 (Jan. 19, 2023).
[13] Docket No. 2019-9-E, Direct Testimony of Derek Stenclik, DESC 2019 Integrated Resource Plan, at 33 (Jul. 10, 2020).
[14] Docket No. 2021-9-E, CCL/SACE/CCEBA Comments on the 2021 IRP Update at 9 (Jan. 14, 2022).

clean energy replacement portfolio for the Williams and Wateree retirements."[15]

- In the 2022 Coal Retirement Study comments, Nonprofit Intervenors stated that, "none of these [clean energy replacement portfolio] recommendations were acted upon by DESC. Presumably, replacement resources were not evaluated in the Charleston load area because the area "currently lacks the high-volume gas pipeline infrastructure needed to support a new large gas-fired generation facility."[16] However, the non-wire, non-pipeline resources would not require the same substantial system upgrades.
- Also in the 2022 Coal Retirement Study comments, Nonprofit Intervenors requested that DESC "[p]rovide model results for an additional sensitivity (i.e. RO6b) in both the TIA Study and PLEXOS analysis that assumes both Williams and Wateree are retired in 2028, and Williams is replaced with a standalone battery storage at the Williams site along with additional demand response and energy efficiency in the Charleston load center."[17]
- In the IRP Stakeholder Session VII comments, Sierra Club "propose[d] scenarios (both PLEXOS LT and ST) that assume coal retirements and no new gas resources are available. This will properly bookend the analysis to show the costs, benefits, emissions, and operations with a clean energy replacement portfolio."[18]

[15] Id. at 36.
[16] Docket No. 2021-9-E, Comments of Sierra Club on DESC 2021 IRP Update, at 3 (Jan. 14, 2022).
[17] Docket No. 2021-192-E, DESC Coal Retirement Study at 14,
[18] Sierra Club comments submitted to IRP Stakeholder Session VII Homework at 8, attached as Exhibit DS-03.

- In the comments to the DESC 2022 IRP Update, Sierra Club specifically recommended "that the Commission require DESC to evaluate at least one scenario in the 2023 IRP that retires the Williams and Wateree coal plants in 2028 and replaces it with a portfolio of 100% clean energy resources, including but not limited to solar PV (utility-scale and distributed), battery energy storage, demand side management, and increased energy efficiency. This scenario should not include any arbitrary annual build constraints to limit the addition of clean energy resources."[19]

Despite these continued requests, DESC's only response was to mischaracterize stakeholders' recommendation, stating that "Sierra Club requests that the Commission order the Company to submit a Build Plan that consists of 100% clean energy resources. This would be a meaningless, unrealistic, burdensome and potentially misleading exercise…"[20] To be clear, neither Sierra Club nor any other stakeholder requested that DESC consider converting its entire resource fleet to "100% clean energy." Rather, stakeholders requested that DESC model a ***replacement*** portfolio specific to the retirement of Williams and Wateree—in other words, to evaluate replacing just those two resources, which represent 19% of DESC's existing capacity with non-fossil fuel energy. The request here is for only the replacement resources to be non-fossil fuel and not for a 100% decarbonized power system. As my modeling results show (Section 4), even in this replacement portfolio example, gas resources would remain a large portion (40%)

[19] Docket No. 2022-9-E, Sierra Club comments to the 2022 IRP Update, at 13, (Jan. 19, 2022.)
[20] Docket No. 2022-9-E, DESC response to the Joint Comments on Dominion Energy South Carolina, Inc.'s 2022 IRP Update at 3 (Feb. 20, 2023).

of DESC's overall resource mix. Indeed, under the repeated, reasonable request of Sierra Club and other parties, gas would remain DESC's largest single energy source.

Q: Did you review DESC's specific IRP assumptions and if so, which ones did you focus on?

A: Yes, I reviewed DESC's IRP assumptions in detail. While there are many that could be changed, I focused my testimony on the following select, key assumptions that have the largest impact on the IRP results and therefore, pose the largest risk to DESC ratepayers:

- Build limits on solar and storage
- Technical life and financing assumptions for battery storage
- ELCC assumptions for battery storage
- IRA multipliers available for solar and storage
- Timeline for coal retirements, ELG retrofits, and the shared combined cycle
- Heat rates for new combined cycle and combustion turbine resources
- Operating constraints for existing combined cycle and new combustion turbines
- Transmission planning and upgrades.

My testimony focuses on a rather limited set of key assumptions and my modeling intentionally made limited additional changes to the IRP assumptions. This was done to simplify the comparison to DESC's own analysis. It does not, however, imply that I support any assumptions that are not addressed in this testimony or that were not adjusted in my modeling results.

Q: What are your concerns regarding DESC's assumed build limits for solar and storage resources in the 2023 IRP?

A: DESC continues to use unrealistic, unsupported constraints on solar and storage resources in its optimized PLEXOS modeling, specifically, limiting the annual build of solar resources to 300 MW per year.[21] This is a critical assumption in the modeling as the constraint is binding *every year* from 2028 to 2036 in the DESC preferred portfolio,[22] and every year from 2026 to 2046 in the High Fossil Fuel Prices Build Plan.[23] This makes any claims of an "optimized" capacity expansion meaningless, as the results are entirely driven by DESC's exogenous, arbitrary assumption that only 300 MW of solar PV can be integrated in a single year. DESC makes no mention of this constraint in the 2023 IRP, or in the 2022 IRP Update, but rather only explains this via discovery responses.[24] DESC states that "[t]he DESC modeling limit is not an explanatory variable or actual limit but does allow the PLEXOS model to create a better representation of the future."[25] That is simply not the case. If that assumption was increased, it would materially affect every resource plan presented.

I raised this issue early in the IRP process via the Stakeholder Session 8 Homework comments, which stated:

> [d]uring Session VIII, DESC proposed annual build limits of 300 MW per year and 150 MW per year of solar and battery storage resources, respectively. Stakeholders expressed concern with DESCs choice to limit annual builds to such a small amount as this

[21] Docket No. 2023-9-E, Direct Testimony of James W. Neely at 36, (Apr. 4, 2023).
[22] DESC 2023 IRP at 13.
[23] DESC 2023 IRP at 59.
[24] DESC Response to ORS 2-11, attached as Exhibit DS-04.
[25] Id. at 3.

> could limit the ability for alternative resources to replace coal retirements. Please include a discussion of DESCs justification for annual build limits of solar and storage and provide sensitivity results if this constraint is relaxed.[26]

Given the need to replace both capacity and energy at Williams and Wateree, this assumption is critical to identifying the least cost, most prudent plan for the accelerated coal retirements. In its 2022 IRP Update comments, Sierra Club stated that "[b]est practices in capacity expansion planning should use the model to inform decision-making, not pre-select, or hard-code data into the model, which is what the annual build limit does."[27] Sierra Club further recommended that "instead of pre-selecting annual build limits, DESC works to understand their ability to actually incorporate potentially over 300 MW/year of solar builds if the model selects them as economically optimal rather than pre-selecting certain outcomes."[28]

To be very clear, while DESC claims the IRP evaluated a wide range of resource candidates to replace Williams and Wateree, they limited builds of clean energy technologies so there was *no available option in the necessary years* for the model to replace the retiring coal capacity without adding new gas.

Q: Is DESC's 300 MW per year solar limit reasonable?

A: No. DESC claims that "both industry consensus and DESC's research conclude that 5%-8% of peak hour load is a reasonable limit for the sustained pace of solar build over years and decades."[29] There is simply no industry consensus, standard, or reasonable technical comparison for DESC to make this claim. DESC also supports

[26] Sierra Club comments to IRP Stakeholder Session VIII at 1-2, attached as Exhibit DS-05.
[27] Docket No. 2022-.9-E. Sierra Club comments to the 2022 IRP Update, at 23 (Jan. 19, 2022).
[28] Ibid.
[29] Ibid.

this claim by referencing historical solar installations in its service territory being at or below 300 MW per year. However, these solar installations are almost exclusively qualifying facilities under PURPA and do not represent a concerted effort or competitive solicitation by the Company to proactively procure solar resources. Furthermore, it is unreasonable to assume that historical interconnection rates should dictate a technical limitation on DESC's future resource additions. This is especially true because historical interconnection rates on DESC's system can only be attributed to developers' willingness to build PURPA facilities and the cost of solar during a given year. Rather than limiting the solar build in the IRP, DESC should be considering ways it can streamline interconnection and PPAs to accelerate solar integration to ensure Williams and Wateree can be retired in a time sensitive manner and replaced with the resources that the modeling shows are optimal.

To date, DESC has provided stakeholders with no actual technical or economic analysis of the limitations on incorporating more than 300 MW/year of solar resources. If DESC, in reality, cannot build the selected amount of solar for legitimate, specified reasons, the Company could adapt its modeling by rolling over annual MW builds into future years and identify changes that could alleviate these issues and increase benefits for ratepayers, such as co-optimizing its generation and transmission planning in an integrated framework. But by pre-selecting a specific outcome for solar deployment, DESC is unable to determine the optimal deployment of low-cost energy resources and plan accordingly, which then diminishes the insight transmission planners have on what proactive transmission investments are needed to actually secure these economically optimized resources for the benefit of ratepayers.

As previously stated in Sierra Club's 2022 IRP Update comments, Joint Intervenors continue to recommend that:

> [t]he Commission order DESC to remove the annual build constraint for solar and storage resources in the 2023 IRP and all future IRP modeling. Any adjustments that DESC feels are necessary to the preferred portfolio should be made in the short-term action plans (rather than to model inputs), with an appropriate justification.[30]

While I agree with DESC that some limits are required from a modeling perspective, they should not be binding every year in the simulation and they should not limit the ability to replace retiring resources in the time allotted.

Q: How are neighboring jurisdictions considering build limits on solar?

A: Part of DESC's justification for the solar build constraints was that similar limits (compared as a percentage of peak load by DESC) were considered for Duke Energy Carolinas.[31] It is worth noting that Duke Energy included significantly higher annual build limits of 750 MW/year or more in its most recent long term plan and agreed to evaluate the constraints would be evaluated on an ongoing basis to adjust to real world experiences as it integrates new solar resources.[32] More recently, Duke Energy has indicated that their preferred target for annual solar builds is approximately 1,200 MW/year with the ability to increase planned procurements by an additional 20% or more if the price of solar comes in below reference prices used in the plan. Additionally, the solar build limits imposed by

[30] Ibid.

[31] DESC response to Sierra Club 1-3, attached as CONFIDENTIAL Exhibit DS-06.

[32] Duke Energy, *Carolinas Carbon Plan: Appendix I Solar*, 2022, available at https://www.duke-energy.com/our-company/about-us/carolinas-carbon-plan

Duke Energy are not strictly based on historical interconnection rates or a percentage of peak load, like DESC is assuming, but rather based on the 2022 Definitive Interconnection System Impact Study (DISIS) which the company acknowledges will be ramped up to allow increasing levels of solar deployment from 2027 to 2030+ with rates starting at 750 MW/year and increasing to 1,350 or 1,800 MW/year depending on the resource mix and scenario.

Thus, while DESC uses Duke Energy's analysis as a basis for their 300 MW/year build limit, Duke Energy's approach stands in significant contrast. DESC has assumed that regardless of current transmission plans or the potential for proactive transmission planning to be undertaken that the DESC system will only ever be able to accommodate 300 MW/year of solar from now until 2050 when trends in the industry indicate that substantial growth in solar interconnection rates can be achieved with adequate and proactive planning.

Q: In addition to the build constraints on solar, are there other examples where solar resources are artificially or unreasonably constrained in the modeling?

A: Yes. DESC's modeling of solar resources relied on a single year of solar generation potential which was based on existing plant locations and technologies that are not necessarily representative of future solar procurements. Specifically, DESC modeled all new solar resources with an annual AC capacity factor of 23.5%. While this is not a completely unreasonable number based on existing installations, new solar installations are deployed with different technologies than historical installations due to cost declines and performance improvements. These technologies include single-axis tracking, bifacial solar panels and deploying solar farms with a higher inverter loading ratio (ILR) which improve the AC capacity factor by optimizing the DC size of the plant and taking advantage of lower DC solar costs relative to the AC inverter size. All of these technological improvements have the effect of increasing solar generation potential across many weather years and conditions, which DESC does not adequately represent in its modeling.

For example, Duke's long-term plan acknowledges that for its existing solar installations, average capacity factors are less than 23%, however, Duke confirmed through discussion with developers that new installations are leveraging the above mentioned technologies and therefore used higher capacity factors estimated at 28% when using both bifacial and single-axis trackers.[33] It should be noted that DESC's territory in South Carolina also offers greater average solar potential than available in North Carolina (26.8% mean AC capacity factor versus 25.8%).[34]

Q: Did DESC use any similar assumptions that constrained selection of storage resources in its modeling?

A: While storage resources were not given an annual build limit like the solar resources, DESC did restrict the years in which battery storage could be selected. The assumptions used by DESC for when storage units could be selected by the PLEXOS model reflect a lack of understanding on what the ELCC analysis is supposed to represent. Based on the ELCC analysis, DESC modeled new 4-hour battery storage resources in two 800 MW blocks. One block is provided a firm capacity rating of 85% (representing its contribution to meeting the PRM), the next

[33]Carolinas Carbon Plan, Appendix I Solar, pg 2, available at https://www.duke-energy.com/our-company/about-us/irp-carolinas.

[34] NREL Annual Technology Baseline, Utility Scale Solar, 2022

block of 800 MW was given a 50% firm capacity rating. The decline in firm capacity ratings between each block of battery storage is consistent with the ELCC study performed by Astrapé.

However, DESC arbitrarily limited the ability for the PLEXOS model to select the 50% firm capacity battery storage resources until 2036 and onward. DESC indicated that this assumption is because "[t]he ELCC of the batteries drops to 50% once all of the 85% ELCC batteries have been built. Making the 50% batteries available after 2036 was the simplest way to accomplish this."[35] This is simply a modeling adjustment to account for diminishing ELCC, but does not reflect the reality that storage can be added earlier. This artificially prevents battery storage resources from being built in the critical window leading up to the Company's planned 2031 Williams retirement date, where batteries could play a role in deferring large new thermal builds. With 2031 being a key year for DESC to retire Williams, constraining half of the batteries available for selection to 2036+ skews the results and undermines the purpose of using the PLEXOS model, which is to determine an optimized resource mix over time rather than predetermining an outcome.

Q: What issues did you discover with battery storage technical life and financing assumptions?

A: In their modeling, DESC assumes that battery storage resources have a technical life of 20 years and the unit must retire after that length of time. While this is not an unrealistic asset life given current battery technology, it is not aligned with the

[35] DESC response to Sierra Club 3-3 at 1, attached as Exhibit DS-07.

battery storage cost and augmentation assumptions used by DESC, which are based on a 30-year asset life. To clarify, DESC uses the NREL Annual Technology Baseline (NREL ATB) for its battery storage cost assumptions. Embedded in the fixed operating costs for all battery storage resources in the NREL ATB is an assumption that the asset undergoes augmentation (replacing degraded cells to ensure battery capacity is constant throughout its life) at 10 years and again at 20 years. The result is that in DESC's modeling, when a battery resource reaches the 20-year mark, DESC accrues significant augmentation costs for those resources and then just retires the asset.[36]

Stakeholders brought this issue up several times at stakeholder sessions with no response from DESC. If DESC insists on assuming a 20-year life for storage assets, then the costs associated with augmentation should be adjusted downwards to reflect lower costs. As discussed further in Section IV below, I addressed this issue by increasing the battery storage life to 25 years in our portfolios. I chose 25 years as a reasonable compromise because DESC provided revenue requirements workbooks in discovery that included a fixed charge rate for batteries based on a 25-year life (though DESC did not use this rate). Using a 25-year life thus allowed us to keep battery life and the WACC consistent in our alternative modeling.

Q: You noted that the probabilistic ELCC and PRM study was an improvement in this IRP, but were there any problems with how it was conducted?

[36] NREL 2022 ATB, Utility-Scale Battery Storage Operations and Maintenance (O&M) Costs, available at: https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage

A: Yes. While the DESC 2023 Planning Reserve Margin Study was an improvement on DESC's previous PRM and ELCC analyses, it had four notable shortcomings that I would like to address.

First and foremost, the ELCC study did not evaluate reasonable levels of solar and storage additions, limiting its analysis to only 900 MW of battery storage additions and 2,935 MW of total solar capacity despite the IRP explicitly evaluating the retirement of more than 1200 MW of coal. While the results show some saturation in storage ELCC, a 4-hour resource still has a relatively high 88% ELCC at the highest levels evaluated in the study, suggesting that additional amounts of solar and storage resources could have additional capacity value. An ELCC study is intended to evaluate the improvement in system reliability from incremental additions of resources. In other words, it is a way to measure the ability of new resources to contribute to reduce load shedding. The quantity of a given resource evaluated is an input into the model, not an output. The study does not determine what quantities of resources should be deployed, but rather how those resources should be reflected in the PLEXOS capacity expansion model.

However, because the ELCC study evaluated such a limited quantity of solar and storage, it is difficult to extrapolate the extent of that additional capacity value.[37] This makes it difficult to extrapolate results further, which is critical to understand how storage resources could be used to replace the Williams and Wateree plants. The analysis also did not evaluate longer duration storage resources, such as an 8-hour battery, which may be useful as ELCC values for 4-hr

[37] DESC 2023 Planning Reserve Margin Study, at 8-9.

resources saturate. In light of this, I recommend that the Commission order DESC to conduct the ELCC study at further levels of solar and storage adoption for the next IRP.

A second issue I have with the PRM and ELCC Study is the adjustments made to solar resource capacity factors. According to Astrapé:

> [t]he profiles for the specific downloaded years (1998 to 2020) came directly from the solar shape output data from [NREL System Advisor Model (SAM)]. The profiles were then scaled and assigned an inverter loading ratio (ILR) such that across the 42 weather years each project would achieve the desired capacity factor as specified by DESC.[38]

There is no mention elsewhere in the report what inverter loading ratio was used, why capacity factors were scaled down, or the impact such a change would have on the results. Given that the system becomes energy-limited at high levels of solar and storage integration (i.e. there are days where storage could be used more if there were sufficient resources available to charge it), arbitrarily reducing energy output from the solar from historical irradiance estimates—especially on winter days—could materially reduce the efficacy of solar and storage to provide resource adequacy benefits.

A third issue in the DESC 2023 Planning Reserve Margin Study and DESC's planning is how thermal resources are counted towards the reserve margin. One issue is that the Astrapé report claims to evaluate a 2026 study year, and yet the Wateree coal plant was not included in that portfolio.[39] It is unclear how that assumption affects the results. And more generally, DESC inappropriately assigned

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[38] Ibid, at 21

[39] Ibid, at 17.

an ELCC to *only* solar and storage resources while assuming gas and coal resources can be counted as perfect capacity (100% ELCC) for reserve margin planning. Doing so is particularly unreasonable because coal and large combined cycle units pose a disproportionate impact on system reliability when they have outages and their outage potential is correlated with winter cold snaps. At a bare minimum, new gas capacity should be discounted to its unforced capacity (UCAP) based on its forced outage rate. More appropriately, new gas resources should be accredited via their correlated outage risk during winter cold snaps, inclusive of both weather dependent outage rates and potential fuel supply disruptions. This is discussed further in Section 5.

Lastly, I would also like to draw attention to the LOLE by weather year results, which show that 74% of all loss of load events occur in weather years 1980 to 1986.[40] This was a period with higher likelihood of extreme cold snaps and colder average temperatures which resulted in winter peak load variance 15-20% higher than normal winter peaks.[41] While using a long historical record is important and I appreciate the transparency in the results, I worry that DESC is being overly conservative in its winter peaks by layering in assumptions on the risk of winter peaks. For reference, Winter Storm Elliott in December 2022 only saw a peak demand of 4.8% higher than the 10-year or 6.6% higher than the previous 5-year average.[42] However, DESC's first year of the P50 winter peak demand forecast jumps to 4,902 MW, or 9.8% higher than the 10-year average. This potentially

[40] Ibid, at 33.
[41] Ibid, at 16
[42] DESC response to ORS 1-55, attached as Exhibit DS-08.

results in double counting the winter risk, which is already embedded in the planning reserve margin which accounts for higher-than-normal winter demand periods.

Q: You have mentioned multiple issues with the build limits and capacity credits assigned to solar and storage. In addition to those issues, did DESC appropriately capture the federal subsidies available under the Inflation Reduction Act?

A: No, DESC did not appropriately incorporate all opportunities and benefits associated with the IRA. As discussed in comments to the 2022 IRP Update:

> [t]he passage of the [IRA] fundamentally changes the energy landscape for at least the next decade by providing incentives for utilities, developers, and consumers to shift towards more efficient and lower cost energy solutions. [...] If DESC acts expeditiously, it is well positioned to capture much of the value offered from the federal incentives over the lifetime of the tax credits. By accelerating the deployment of zero emissions resources and battery storage technology, DESC can lower costs and provide clean and reliable power. [...] DESC should take prudent action to differentiate resources that can target energy communities or existing interconnections where plant retirements are occurring or where there is low capacity utilization (at peaker plant sites). DESC should assume these bonus credits are available for candidate resources as these are already high priority locations for investment based on current TIA results for retiring Wateree and Williams.[43]

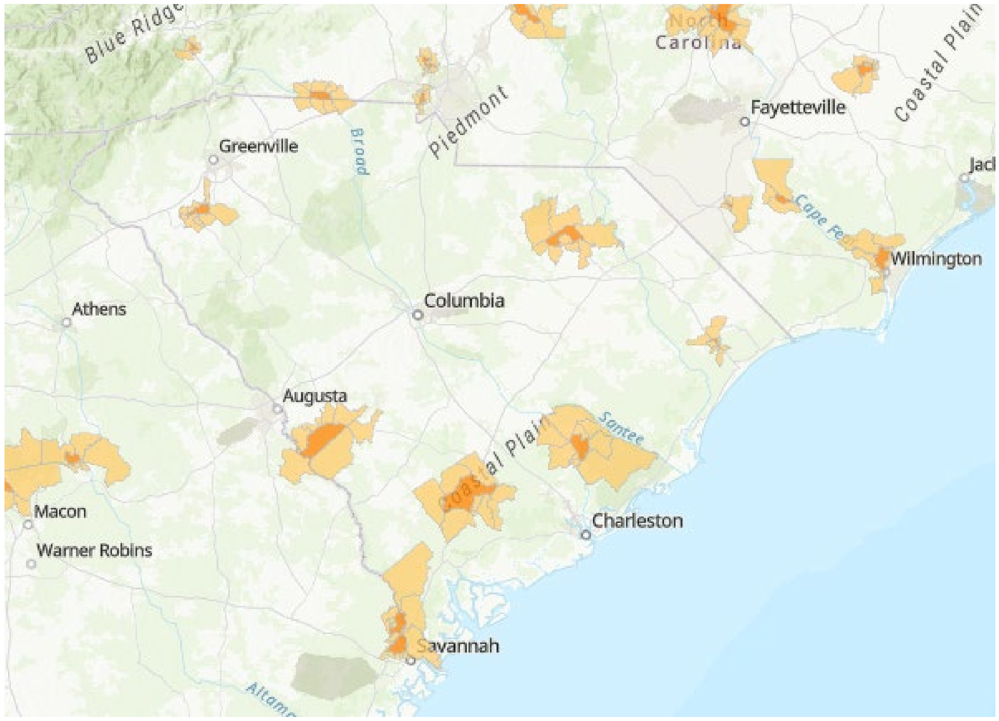
Despite these recommendations, DESC did not incorporate any bonus credits for either Energy Communities or Domestic Content in their analysis and assumed no bonus credits were available for new solar and storage resources. While it is unclear if and how domestic content bonuses will pass through to developers and offtakers, the energy community bonus credit provides a unique opportunity

[43] Docket No. 2022-9-E, Sierra Club comments to DESC 2022 IRP Update at 6 (Jan. 19, 2023).

for DESC. If resources are sited in census tracts with retiring coal plants, for example, they are eligible for a 10% bonus credit to the investment tax credit (ITC) or an additional 0.26 cents/kWh production tax credit (PTC). This means that a resource located in a Designated Energy Community could increase its federal subsidy from 30% up to 40-50% of the upfront capital cost or receive an additional 20% PTC. This significantly changes the project economics of clean energy resources. Unfortunately, DESC implicitly assumed in their modeling that *no* projects could receive these bonus credits because exact siting is not known at this time.

A map of the South Carolina Designated Energy Communities is provided in Figure 1. A large portion of the state, and particularly DESC's service territory, is available for these bonus credits. While it is unlikely that all proposed solar additions could be sited in these census tracts, it is likely that many will be. And it is entirely reasonable to assume that *all* standalone battery energy storage projects could be located in the census tracts to receive a 10% IRA bonus credit. It is also a real possibility that those battery projects could be sited at the same locations as the retiring Williams and Wateree coal plants to leverage existing plant interconnection and transmission infrastructure.

Figure 1. Map of South Carolina Designated Energy Communities[44]



Not only did DESC fail to model the impact of energy communities credit, but, for the IRA credits it did model, it assumed those credits would sunset earlier than is reasonable. In its modeling, DESC assumes that all Solar resources receive a PTC starting at $26.00 per MWh (2021$) escalating annually and that Battery resources receive a 30% ITC on 85% of the total project cost, and notes that not all project costs qualify for an ITC under IRS rules and 85% is a reasonable estimate of the project components that will qualify. DESC also assumes in its modeling that the ITC and PTC apply to projects completed during the life of the program and for

[44] U.S. Department of Energy, National Energy Technology Laboratory (NETL), available at: https://energycommunities.gov/energy-community-tax-credit-bonus/

two years after the program closes to capture projects grandfathered into eligibility that were started before the sunset date.[45]

As a result, DESC assumed *no* bonus credits for solar or storage resources attributed to energy communities and that the bonus credits decrease starting in 2035 and sunset by 2037, which the legislation provides would only occur if the U.S. reaches US GHG emissions less than 25% of 2022 levels by 2035. General consensus is that the US will likely not achieve this goal by the time the IRA is set to sunset, and thus the credits would continue. While this may not warrant an extension in the Reference Case assumptions, it does warrant a sensitivity and provides additional upsides for portfolios that continue to build solar and storage resources later in the study horizon.

Finally, it is worth noting that pursuing the energy community bonus credits could generate additional benefits besides lower cost resources for DESC ratepayers. The siting incentivized under the credits could provide jobs and tax revenue for the communities where the Williams and Wateree coal plants are located, and for other communities impacted by the switch from coal to gas over the past several decades. Not only should DESC include the bonus credit in its modeling, it should be actively pursuing opportunities to site resources in these communities to help offset the economic impacts of coal retirements and support workforce development in new and growing industries.

I therefore recommend that DESC assume that the Energy Community Bonus Credit be assigned to all battery storage resources and that a portion of the

[45] DESC 2023 IRP at 22

proposed solar resources also be modeled with this credit. DESC should also qualitatively recognize that benefits could be higher in the likely event that the U.S. does not achieve the GHG emissions reductions necessary to sunset the IRA legislation.

Q: Are there any problems with DESC's proposed timeline for coal retirements and the proposed Effluent Limitation Guidelines ("ELG") upgrades?

A: Yes. DESC's ELG compliance plans violate Commission Order No. 2020-832 and foreclose the possibility of early retirement at Williams. DESC has pushed back the earliest feasible retirement date for Williams from 2028 (selected by the 2020 Modified IRP and 2021 IRP) to 2030, leaving ratepayers on the hook for *at least $90 million* of retrofits to comply with the 2020 ELG rule regardless of the economic merits of keeping Williams online, simply to extend the life of the plant by only *two* additional years.

The only reason the ELG retrofit is being added at all is because DESC claims that replacement resources cannot be available in time to meet the ELG compliance deadline. 2031 is still several years away, and DESC pushed back their earliest feasible retirement date for Williams largely due to the long lead-time for transmission and pipeline permitting and construction. However, they did not consider faster alternatives - like storage - that could avoid that infrastructure altogether.

The 2020 ELG rule extended the deadline to comply with the rule to December 31, 2025,[46] but allowed companies like DESC to avoid this 2025 deadline by submitting a Notification of Planned Participation ("Notice") to the South Carolina Department of Health and Environmental Control ("SCDHEC") by October 13, 2021,[47] informing them that the Company would either retire the plant by December 31, 2025 *or* opt in to the Voluntary Incentive Program (VIP), which requires more stringent treatment, with a later compliance deadline of December 31, 2028.[48] The deadline to file the Notice to retire a coal plant (cease burning coal) was subsequently extended to June 27, 2023.[49] DESC did not file a Notice with SCDHEC to either retire Williams or opt into the VIP. As demonstrated in Table 3, DESC was telling the Commission, its customers and interested parties that its preferred path forward was early retirement of *both* Williams and Wateree, and yet, its internal documents from July 2021 show they were moving forward with the standard ELG route for Williams with a compliance date of December 31, 2025.

Table 3. DESC's Timeline for ELG Decision-Making[50]

May 1, 2018	SCDHEC issues Modified NPDES Permit for Williams stating that ELG compliance deadlines effective Nov. 1, 2020 unless an Applicability Study is submitted.
August 24, 2020	DESC submits ELG Applicability Study requesting Dec 31, 2023 compliance deadline for Williams

[46] 85 Fed. Reg. 65640 (Oct. 13, 2020); see also 40 C.F.R. §§ 423.13(g)(1)(i); (h)(1)(i); (i)(1)(i); (k)(1)(i); see also 40 C.F.R. § 423.11(t).
[47] 40 C.F.R. § 423.19(f).
[48] 40 C.F.R. §§ 423.19(g)(2)(i), (g)(3)(i).
[49] 88 Fed. Reg. 18440 (March 29, 2023).
[50] See Docket No. 2021-192-E, Joint Intervenors Comments on Coal Retirement Stud at XX, (June 28, 2022) for supporting documentation on the timeline.

October 2020	2020 Amended ELG Rule published
October 2020	SCDHEC issues LOA-005505 giving DESC additional year to assess the new 2020 ELG rule and determine if new compliance dates are warranted
December 2020	Order No. 2020-832 requiring a coal retirement analysis be performed prior to a decision on ELG retrofits at Wateree and Williams.
February 19, 2021	Modified 2020 IRP: Selects RP8 as preferred portfolio: retirement of Wateree and Williams in 2028
March 2021	DESC internal presentation selecting VIP for both Wateree and Williams, compliance deadline of Dec 31, 2028
July 2021	DESC internal presentation selecting standard ELG compliance route for Williams: Dec 31, 2025
August 17, 2021	2021 IRP Update: Selects RP8 as preferred portfolio: retirement of Wateree and Williams in 2028
September 24, 2021	DESC letter to SCDHEC requesting Dec. 31, 2025 ELG Compliance Date
October 13, 2021	Notice of Participation in VIP for Wateree Station
May 16, 2022	Coal Plant Retirement Study Filed

By locking in the standard ELG compliance route for Williams DESC committed to upwards of $90M in capital expenditures when it could have avoided those costs by filing a Notice with SCDHEC to give itself more time and a range of options for ELG compliance at Williams including retirement or VIP, both by the end of 2028.

In addition, in March 2023, EPA issued a proposed Supplemental Steam Electric ELG and Standards Rule, which has a zero discharge requirement for both flue gas desulfurization and bottom ash transport water and a compliance deadline of December 31, 2029.[51] Since DESC chose the standard ELG compliance route, *additional* costs and retrofits will be needed for Williams to comply with the proposed 2023 ELG rule. At this time, because it is a proposed rule, DESC has not yet evaluated the costs for the retrofits necessary to meet the 2023 ELG proposed rule, but they could be significant.[52]

Q: In the 2022 IRP Update you noted issues with the heat rates of new combustion turbines and combined cycle resources. Are there any issues with heat rates in this IRP?

A: Yes, there are significant issues with the heat rates, or fuel efficiency, DESC assumed for new combustion turbines and combined cycle candidates in the PLEXOS model. Specifically, DESC used heat rates that are much lower (more efficient) than actual plant characteristics. I believe this to result from a confusion between two values provided by gas turbine original equipment manufacturers such as General Electric (GE) and Siemens: lower heating value (LHV) and higher heating value (HHV). The difference between the two calculations is based on whether the heat rate is calculated assuming water is in liquid form (HHV) or vapor form (LHV) and results in approximately an 11% difference in the quoted fuel efficiency. Equipment manufacturers typically quote the heat rate for their

[51] 88 Fed. Reg 18824 (March 29, 2023).
[52] DESC Response to Sierra Club 2-1 at 1, attached as Exhibit DS-09.

equipment in LHV to provide a relative and consistent benchmark of the heat rate process. However, gas plants actually use water in liquid form, so for true energy calculations that use gas—such as power system modeling—HHV values are the correct ones to use. As a result, DESC by using LHV is artificially making their new thermal unit heat rates 11% more efficient than reality and other gas generators on the system. This makes the combined cycle and combustion turbine technologies appear more competitive than they are by understating fuel consumption and costs.

Stakeholders raised this issue in January 2023 in comments following a stakeholder session, stating that:

> heat rates for the combined cycle units look to be representing Lower Heating Values (LHV) rather than Higher Heating Values (HHV). This is an important distinction because actual fuel consumption for the generators will be driven by the HHV, which is approximately 11% higher than the LHV. For reference, GE provides sample technical specifications for new H-Class combined cycle technologies and quotes values in LHV which align well with the DESC assumptions and seem to point to the CC heat rates using LHV versus HHV. If the heat rates quoted by DESC are in LHV then the efficiency of the plant is overstated by approximately 11% and the heat rates should be adjusted upwards.[53]

However, DESC did not address these comments or change their modeling.

In subsequent discovery, DESC confirmed that “heat rates modeled are based on Lower Heating Value (LHV), and they represent gross load heat rates for new generation,”[54] but provided no additional information or justification. In a later discovery response, DESC stated that “DES Project Construction supplies the thermal generator specifications in the “Greensheets” in gross heat rates based on

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[53] CCL/SACE and Sierra Club CONFIDENTIAL comments submitted in response to DESC Stakeholder Session X, (Jan. 10, 2023) at 7, attached as Exhibit DS-10.

[54] DESC response to Sierra Club 1-5 at 1, attached as Exhibit DS-11.

LHV. [...] New thermal resources use LHV and existing resources use HHV [and] the natural gas price modeled in the DESC model is in HHV units."[55]

While DESC acknowledged the issue of the LHV vs. HHV confusion, they made no attempt to explain their rationale or correct the problem. This artificially, and incorrectly, improves the efficiency of gas resources under DESC's assumptions. As a result, DESC's IRP underestimates the amount of fuel these resources will require—additional fuel that ratepayers will have to pay for and which will increase the risks associated with fuel price volatility.

Q: You mentioned that DESC is modeling both existing combined cycle units and new combustion turbine units with overly conservative assumptions. Can you please explain?

A: Yes. First, the existing combined cycle units are being modeled with extremely conservative minimum up and down time assumptions which force the unit dispatch to be unrealistic when lower cost resources are available. For example, in the PLEXOS model, DESC assumes that the Urquhart CC must operate for a minimum of 12 hours when turned on and remain offline for 24 hours if cycled down. For Columbia Energy Center (CEC) and Jasper—which are major baseload plants on the DESC system—the DESC PLEXOS modeling assumes they must operate for a minimum of 24 hours when turned on and remain offline for 48 hours if cycled down. These assumptions do not reflect the actual capability of combined

[55] DESC response to Sierra Club 3-5 at 1, attached as Exhibit DS-12.

cycle plants to operate flexibly. Typical operating constraints for combined cycle units are in the range of 6-8 hours on and 6-8 hours off.[56,57]

By limiting the flexibility of existing units, the production cost model cannot efficiently dispatch lower cost resources when generation is high, nor can it as efficiently turn these units on when they are needed if the minimum down time has not passed. This has the effect of increasing solar curtailment and increasing system costs. In my alternative modeling, discussed in Section IV, I chose to model these existing units with more representative constraints, assuming a minimum up time of 6 hours and minimum down time of 8 hours.

Regarding new combustion turbine units, DESC assumes a minimum up time of two hours and a minimum down time of four hours. These are less egregious than DESC's assumptions for combined cycle units, but it unnecessarily limits the ability of new peaking resources to quickly respond to load or variable renewable energy output. Modern combustion turbines are capable of reaching full load within minutes with no requirements for minimum operating periods. I chose to model these new units with minimum up and down times of 1 hour to match the resolution of the production cost model used by DESC.

Q: Do you have any comments related to the transmission costs DESC attributes to coal retirements?

[56] National Renewable Energy Laboratory, *The North American Renewable Integration Study (NARIS),* at 22, https://www.nrel.gov/docs/fy21osti/79224.pdf

[57] PJM, *Unit Specific Minimum Operating Parameters for Generation Capacity Resources,* 1/18/2022, https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx

A: Yes. As stated in previous comments, I have concerns with how the Transmission Impact Assessment (TIA) was conducted and how DESC is ascribing the transmission upgrade costs to the coal retirement decision. Given that all of the portfolios evaluated in the TIA included several hundred MWs of gas builds,[58] it is difficult to ascertain the primary cause of transmission overloads. DESC contends that to reliably retire the Williams coal plant, for example, a transmission upgrade of $309 million is required. However, much of that cost is not a result of retiring Williams, but rather upgrading the system to accommodate several hundred MWs of new gas capacity. DESC claims that the $309 million transmission upgrades are necessary "[redacted]"[59] However, DESC also attributes the extensive upgrades as being "[redacted]"[60] This highlights the cost-saving benefits of identifying how much additional capacity can be added *before* triggering transmission upgrades. Here, DESC failed to take that key step by refusing to evaluate a scenario where replacement resources were located in the Charleston load area, without a significant generation build also occurring at Canadys.

Strategically located standalone storage, energy efficiency, demand response, and distributed energy resources could go a long way towards offsetting the $309 million transmission need as determined by the 2021 TIA Study. In Sierra

[58] DESC 2023 Integrated Resource Plan at 29.
[59] DESC CONFIDENTIAL response to ORS 1-10, attached as CONFIDENTIAL Exhibit DS-13.
[60] DESC CONFIDENTIAL response to ORS 1-10, attached as CONFIDENTIAL Exhibit DS-13.

Club's comments to the 2022 IRP Update, and in the IRP Stakeholder Session 7 feedback, Sierra Club suggested additional TIA scenarios. These were provided even before the official comments in the Coal Retirement Docket and DESC's request for input on additional TIA study scenarios. Sierra Club has routinely requested a TIA scenario with local replacement resources in Charleston - especially standalone storage at the Williams site- and without concurrent gas builds at Canadys - which require major transmission upgrades. However, stakeholders have not been given results or a reasonable explanation of why such replacement would not mitigate or defer transmission and gas pipeline infrastructure needs.

In the 2022 TIA, DESC evaluated three sizes of battery storage located at the Williams site, ranging between 100 MW (Case 5A) and 300 MW (Case 5C), but unfortunately all three of those cases also included a large gas build at Canadys. According to DESC:

> the results of those studies found that, in a least cost scenario, a 100 MW battery system paired with the other generator replacement options described in Case 5A would require in total transmission upgrades of \$332 million. Case 5B, which included a 200 MW battery system, would require \$210 million in transmission upgrades. Case 5C, which included a 300 MW battery, would also require \$210 million in transmission upgrades.[61]

In other words, siting battery storage at Williams and within the Charleston load pocket reduced the TIA upgrades by *at least* \$100 million. The remaining \$210 million is likely "[redacted]"[62] Stakeholders

[61] DESC response to Sierra Club 1-6 at 2, attached as Exhibit DS-14.
[62] DESC CONFIDENTIAL response to ORS 1-10, attached as CONFIDENTIAL Exhibit DS-13.

repeatedly asked DESC to evaluate the further potential transmission cost savings of placing larger standalone facilities at Williams and reduced gas capacity at Canadys, but DESC refused. A few simple model runs likely stand between ratepayers and hundreds of millions of dollars of cost savings.

I therefore continue to recommend that the Commission require DESC to conduct a new TIA with a larger standalone storage resource at Williams (up to 600 MW) and to identify the maximum size resource that can be sited at Canadys without triggering significant transmission upgrade costs. As noted here, this could save ratepayers at least $100 million and possibly closer to $300 million. These solutions are not identified, in part, because DESC generation and transmission planning is not done in an integrated manner, but rather via discrete TIA requests between the two divisions.

Q: Are there ways that DESC can incorporate integrated generation and transmission planning?

A: Yes, but unfortunately DESC generation and transmission planning remains siloed. In my previous comments, I outlined three options available to DESC to better integrate transmission and generation planning to ensure that resources are sized correctly and located in the correct areas.[63] These include a zonal transport model in PLEXOS, a nodal transmission model in PLEXOS, or economic dispatch models in the AC contingency analysis. In its reply comments, DESC suggested that this was "imposing a complex new zonal or nodal structure."[64] However zonal and

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[63] Docket No. 2022-9-E, Sierra Club comments to the 2022 IRP Update, at 18 (Jan. 19, 2023).

[64] Docket No. 2022-9-E, DESC Reply to the Comments of Sierra Club and Joint Intervenors to 2022 IRP Update (Feb. 20, 2022).

nodal transmission modeling is a standard feature in PLEXOS and commonly used by power system planners across the industry. While it does not replace the need for detailed AC contingency analysis like the work conducted in the TIA, it can facilitate coordinated planning between generation and transmission needs, which can enable significant ratepayer cost savings.

Q: In your review of the 2023 IRP, previous IRPs, and the Stakeholder Sessions, have you observed a bias from DESC regarding new combined cycle or combustion turbine generators?

A: Yes, as my preceding answers discussed, I have seen a clear and consistent bias in DESC's analysis for new gas capacity, and particularly the shared combined cycle resource in the preferred plan. Specifically, there are at least six areas where this bias can be seen. Some of these issues were identified in the previous section, but they are summarized below.

1. No portfolios were evaluated without new gas resources. Even if the new gas generators are least-cost under DESC's assumptions, there is enough uncertainty on cost, timeline, pipeline availability, and regulations to warrant the evaluation of at least one portfolio where non-fuel resources are used to replace Williams and Wateree rather than new gas. In fact, DESC acknowledges such constraints, observing that:

> [a] principal risk in pursuing a Shared Resource, or other combined cycle generation plant, will be the permitting and construction of pipeline capacity to serve the new plant site(s), as would be expected in the current environment for generation projects that depend on significant new supplies of natural gas in an underserved area.[65]

[65] DESC 2023 Integrated Resource Plan, at 29.

2. Heat rate assumptions are artificially low. As stated above, the assumed heat rates for new combined cycle and combustion turbine resources were quoted in LHV, and thus are 11% lower (more efficient) than reality, making the costs attributed to a new gas resource appear lower than they actually are.

3. Build limits on solar and storage are unreasonably restrictive and unreasonably restrictive. Annual build limits on solar resources and limitations on years when battery storage can be built severely limit options available to replace retired Williams and Wateree capacity.

4. IRA bonus credits for projects in energy communities were not applied. This is a missed opportunity for DESC's ratepayers and inflated the actual cost for standalone storage resources and some solar builds.

5. Transmission costs are assigned to coal retirements rather than new gas units. DESC incorrectly assumes that retiring Williams will require $309 million in transmission upgrades, regardless of how it is done. DESC thus assigns $309 million in transmission costs to "coal retirement," rather than assigning these costs only to the plans that include major gas plant additions—which is more likely the actual trigger for these particular transmission costs. In fact, portfolios reliant on solar, storage, and demand side management may help avoid transmission upgrades that would be needed to build a combined cycle gas resource larger than the interconnection capacity available at the existing site.

6. Gas capacity is counted in full for the reserve margin calculations. DESC currently assumes that it can count a gas and coal resource's entire capacity towards the reserve margin and fails to reduce its capacity accreditation based on outages. Williams, for example, has a 22% planned outage rate and a 14% forced outage rate, and thus is unavailable a large portion of the year to support reliability. Furthermore, large units like Williams and combined cycle plants, which are large relative to system demand, can have a disproportionate effect on loss of load expectation. In addition, thermal resources can have correlated outages—particularly during winter cold snaps—that further exacerbate winter reliability risk. Yet, they are treated by DESC as having perfect capacity for reserve margin planning.

While it is impossible to know why such a large bias for new gas capacity exists, it is worth noting that DESC has a financial incentive to recover costs associated with a new capital project costing hundreds of millions of dollars and is indifferent to fuel costs because those are passed on to customers. A singular focus on new gas capacity is leading DESC to select a preferred plan that lacks resource diversity (committing to nearly 60% gas generation by 2031), overlooks opportunities for DESC to fully capture federal subsidies available in the IRA, increases cost for ratepayers, and creates unnecessary risk.

III. RISKS IN DESC'S PREFERRED PLAN

Q: DESC claims their preferred plan has a diverse resource mix. Is this true?

A: No. The generation mix in DESC's preferred plan is nearly 60% gas in 2031 (as a percentage of generation, on an energy basis). Furthermore, DESC's discussion of "generation diversity" in the IRP is misleading, measuring resource diversity not as a function of generation (MWh), but as a function of capacity (MW). In ranking the generation diversity of portfolios DESC states, "[u]nder this analysis, a plan that leads to a generation system with a single type of generation asset representing 50% of its generation mix would have less generation diversity than a plan where no generation resource type represented more than 45% of its generation mix."[66]

DESC's ranking is not logically consistent and could lead the Commission to misunderstand the degree to which its preferred portfolio would rely on a single fuel—gas. By using nameplate capacity for its fuel diversity analysis, DESC claims that solar is the largest part of its generation mix. But to be consistent in a capacity-based ranking, DESC would need to use the effective capacity of solar that it counts toward the reserve margin, which would lead to dramatically lower solar capacity share. A proper evaluation that is based either on annual energy production or on effective capacity would show that DESC's gas resources account for the majority of its resource mix, representing nearly 60% of the annual generation and over 60% of the reserve margin requirement.[67]

As a result, solar and storage additions would actually increase resource diversity and mitigate the negative consequences of fuel price volatility and potential future environmental regulations.

Q: A shared combined cycle resource is an integral component of DESC's preferred plan. Do you believe that poses any unaccounted-for risks to DESC ratepayers?

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[66] DESC 2023 IRP at 67.

[67] Resource generation (MWh)--not capacity contribution--determines the amount of fuel burned at the plant and thus customer exposure to fuel cost volatility. As a result,it makes sense to look at generation when considering whether a resource mix is diverse (a key way to mitigate fuel cost volatility). Alternatively, DESC could use firm capacity (i.e. effective capacity counted towards the reserve margin) to show which resources are being relied on for reliability to quantify resource diversity.

A: Yes, there are several risks associated with a shared combined cycle, many of which were not evaluated in the IRP but warrant a qualitative discussion. These include stranded asset risk, timeline risk, gas price risk, risk of cost overruns, uncertainty in future regulatory requirements, and reliability risks associated with large units. These risks are difficult to quantify in modeling exercises but should be addressed qualitatively and considered by the Commission.

Q: Why is there a stranded asset risk associated with the proposed shared resource?

A: A shared combined cycle resource is a large, 662 MW single investment for DESC that requires a definitive decision soon. This 662 MW represents nearly 15% of DESC's average winter peak load from the past five years (4,504 MW).[68] By 2035, DESC's winter peak demand forecast reaches 5,228 MW or 724 MW higher than the average from the past five-years. If that load growth doesn't materialize as fast as predicted, and the shared resource is built, DESC will be overbuilt. This is already the case today, where DESC is predicted to have a 30% reserve margin until Williams and Wateree are retired, 10% more than DESC claims is required.

More modular resources, like solar and storage, can be deployed over time and can achieve economies of scale without requiring commitment to a large, single investment, as is required for a plant like the shared combined cycle. Solar and storage resources also have a faster development cycle, especially for standalone storage. As a result, solar and battery energy storage can be built incrementally throughout the horizon, either increasing or decreasing cumulative builds to meet

[68] Based on calculations from DESC response to ORS Discovery 1-55, *see* Exhibit DS-08.

changing load. This optionality would avoid much of the downside, stranded asset risk that accompanies a single 662 MW resource.

Q: Does the shared resource also pose a coordination challenge, and how might that affect project timelines?

A: Yes, unlike solar and storage resources, DESC would be staking the feasibility of coal retirements and, potentially, the future reliability of its grid, on a single, high stakes project, rather than a portfolio of projects where the failure of any one would be less likely to pose reliability risks and more easily addressed. Simply put, DESC is putting a lot of eggs into one basket. Because the shared resource also poses coordination and timeline challenges, these risks are exacerbated. First and foremost, a shared resource would also require commitments and approvals from Santee Cooper. Furthermore, the project would be beholden to a myriad of permitting challenges spanning the gas pipelines, new transmission, and for the generation itself. DESC acknowledges this risk in the Coal Retirement Study, stating that transmission improvements alone would take between four and eight years to complete and gas pipeline planning and construction would take five years.[69] Likewise, in its 2023 IRP, DESC acknowledges that "a principal risk in pursuing a Shared Resource, or other combined cycle generation plant, will be the permitting and construction of pipeline capacity to serve the new plant site(s)."[70] These potential roadblocks and coordination challenges risk delay for a shared resource. At best this would mean keeping Williams online longer, at worse it could

[69] Docket No. 2021-192-E, DESC Coal Retirement Study, at 7 (May 16, 2022).
[70] DESC 2023 Integrated Resource Plan, at 29.

pose a reliability risk. Keeping Williams online longer would also be risky due to proposed new GHG rules that would either require limited operation of the coal plant or costly carbon capture and sequestration retrofits.

No resource is immune to this risk. Solar and storage resources would likely have similar permitting challenges and transmission needs, but this risk can be spread over many projects. If individual projects are delayed or fail to reach completion the remaining portfolio of resources is still available. The human capital required for project development would also be spread across many different developers and the financial risk of failed projects is borne by the developer rather than DESC ratepayers.

Q: Natural gas prices have been notably volatile over the past few years. What happens if that volatility continues or if natural gas prices increase in the future?

A: A commitment to a shared combined cycle plant would also be sensitive to fluctuations in natural gas prices. This risk is borne by the ratepayer as fuel costs are 100% passed through in electricity rates. In DESC's preferred portfolio, the shared resource or alternative gas plants, represents an *uncertain and variable cost* in the future NPV analysis. In contrast, a Williams and Wateree non-fossil fuel replacement portfolio, represents a *certain and fixed cost* from a long-term power purchase agreement (PPA) that does not fluctuate due to natural gas prices. In other words, a solar and storage portfolio provides a hedge against future gas prices and bill certainty for ratepayers.

Q: What about cost overruns, does that also pose a risk for DESC ratepayers?

A: Yes, DESC's preferred plan also poses risk of cost overruns. Similar to gas price volatility, potential cost overruns for a shared combined cycle project is a risk ultimately borne by the ratepayer. This risk is especially acute in South Carolina, where the scrapped V.C. Summer nuclear reactors cost SCE&G customers $3.8 billion.[71] Research shows that actual costs of large power plants, on average, are 36% higher than expected, while benefits are 6% lower than expected.[72] In contrast, cost overruns for PPA solar and storage units is a risk borne by the project developer and asset owner, effectively shielding the ratepayer from this risk. This risk is further mitigated because projects are spread across many different sites, developers, and equipment manufacturers.

Q: In previous testimony you have stressed the importance of recognizing the risk of future regulatory requirements. Do you believe that applies to the shared combined cycle resource as well?

A: Yes, there are also financial risks for ratepayers associated with potential future environmental policies and CO_2 pricing at the state or federal level. Changes to state or federal policy could adversely affect the costs, operations, and projected benefits of a shared combined cycle resource - especially compared to alternative portfolios that rely more heavily on clean energy technologies. DESC's medium CO_2 cost and high CO_2 cost assumptions serve as "a proxy for future policy that

[71] S&P Global, *SCE&G customers will ultimately pay $3.8B for VC Summer under Dominion deal*, https://www.spglobal.com/marketintelligence/en/news-insights/trending/j-er9puvwggi8sgh2nps5a2#:~:text=SCE%26G%20customers%20will%20ultimately%20pay%20%243.8B%20for%20VC%20Summer%20under%20Dominion%20deal,-Share&text=South%20Carolina%20Electric%20%26%20Gas%20Co,pay%20off%20its%20nuclear%20debt.

[72] Flyvbjerg, B. and Bester, D., *The Cost-Benefit Fallacy: Why Cost-Benefit Analysis Is Broken and How to Fix It,* Journal of Benefit-Cost Analysis, October 2021.

increases the cost of fossil-fired resources."[73] However, this does not shield ratepayers entirely from uncertainty associated with future regulatory requirements.

Q: Can you provide an example? Are there any proposed environmental rulemakings that would adversely affect the proposed combined cycle?

A: Yes, an example of potential regulatory risks that could adversely affect new gas resources is the EPA's proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants released May 23rd, 2023.[74] The EPA's proposed rule:

> propos[es] Clean Air Act emission limits and guidelines for carbon dioxide (CO2) from fossil fuel-fired power plants based on cost-effective and available control technologies. The power sector is the largest stationary source of greenhouse gasses (GHGs), emitting 25 percent of the overall domestic emissions in 2021. These emissions are almost entirely the result of the combustion of fossil fuels in the electric generating units (EGUs) that are the subjects of these proposals.[75]

In summary, the proposed rule would establish performance standards for fossil fuel-fired stationary combustion turbines (primarily new gas units) based on the unit's capacity factor. This would require some combination of reduced operation (lower capacity factor), the use of carbon capture sequestration, and/or co-firing low-GHG hydrogen:

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[73] *See* DESC response to ORS 1-26, attached as Exhibit DS-02.

[74] 88 Fed. Reg. 33240 (May 23, 2023), available at: https://www.govinfo.gov/content/pkg/FR-2023-05-23/pdf/2023-10141.pdf

[75] EPA, *Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule,* *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*

- New CT/combined cycles operating with a 20% capacity factor (or more up to the upper limit of design efficiency) must start burning 30% Hydrogen by 2032 and 100% by 2038.
- New base load CT/combined cycles following the carbon capture sequestration pathway, must capture 90% CO_2 by 2035. If following the Hydrogen pathway, must co-fire 30% low GHG Hydrogen by 2032 and co-fire 96% Hydrogen by 2038.
- Existing CT must meet either 90 percent capture of CO_2 using carbon capture sequestration by 2035, or co-firing of 30% by volume low-GHG hydrogen beginning in 2032 and co-firing 96% by volume low-GHG hydrogen beginning in 2038.[76]

Because a new combined cycle would operate at a high capacity factor, the proposed rule would mean substantially higher capital costs and fuel costs for that type of gas resource in particular.

The proposed rule also provides several options for coal plants based on the retirement dates they are willing to accept. Units that are willing to retire by 2032 can maintain, but not increase, their current emission rate. If they are willing to accept an operational limit of 20% of full capacity starting in 2030, they can continue to operate until 2035. Units that choose not to accept those limitations but are willing to retire before 2040 will be required to co-fire at least 40% natural gas starting in 2030. Finally, units that wish to continue operating past 2040 must install carbon capture and storage technology and begin capturing 90% of their CO_2

[76] 88 Fed. Reg 33240, 33244-45 (May 23, 2023).

emissions starting in 2030. Alternatively, coal plants that fully convert to gas or oil before 2030 by removing their technological capacity to fire coal will not be categorized as coal plants and will be permitted to maintain their post-conversion emission rate without backsliding (but without further reductions required).

I am not claiming that DESC should have planned for this specific rulemaking in its IRP, and the proposed rule is not final. However, it is indicative that potential regulatory requirements are plainly foreseeable and could occur in the form of greenhouse gas standards, CO_2 pricing, etc., which will have major economic impacts on fossil-fuel burning plants that must be considered when evaluating the potential risks of building the *new* joint combined cycle plant in DESC's IRP.

Now that DESC, the Commission, and stakeholders know of this proposed new rule, all parties need to account for it because the cost implications to ratepayers could be huge and long lasting.

Q: Finally, what are the reliability risks of a combined cycle generator?

A: A large combined cycle addition would constitute a large, single, block of capacity in DESC's resource portfolio. The 2x1 combined cycle configuration would have a total capacity of 1,325 MW and loss of up to 650 MW assuming one gas turbine is down and the steam turbine is limited due to reduced steam flow. This represents approximately 13% of DESC's peak load. When the units go on forced outage, it represents a large loss of capacity in a single outage (also known as a single contingency). While a new combined cycle generator would likely have a high availability rate, sustained outages can and do occur, and can be more likely during the first few years of operation. Even if this outage risk is shared with Santee Cooper, a 325 MW outage is material to DESC's resource adequacy.

Furthermore, these outages are much more likely to occur during extreme winter conditions, exactly the time when they are needed most for reliability. This was evident during Winter Storm Elliott (December 2022) when 1200 MW of thermal capacity was unavailable during critical winter demand periods. Correlated outages pose one of the largest risks to resource adequacy for DESC and other utilities in the region. Fuel supply constraints could further exacerbate these availability challenges.

The shared resource could likewise represent a large loss of capacity for DESC stemming from a single failure mode. In contrast, battery storage and solar PV technology is highly modular and can be distributed across the system. This means the likelihood of a failure removing an equal amount of battery storage or solar PV capacity compared to the loss of the combined cycle would be highly unlikely and easily designed to prevent.

This type of supply-side uncertainty is one of the primary factors that influences DESC's reserve margin requirement, along with load uncertainty and weather. With fewer large contingencies, there is less risk of lost capacity due to a single event. Replacing coal generation with a diverse and distributed set of smaller solar and storage plants would decrease this reliability risk for DESC.

<u>IV. INDEPENDENT MODELING OF ALTERNATIVE PORTFOLIOS</u>

Q: Did you perform independent modeling of the DESC system to evaluate alternative resource portfolio options?

A: Yes. To better evaluate alternative portfolio options, I independently modeled DESC's system. First, I recreated the models and processes developed by DESC, to the closest extent reasonable, and then tested alternative portfolios to gauge the effect of changing the assumptions outlined previously in this testimony, specifically, by quantifying the operating, fixed, and capital costs of the new portfolios.

This analysis is not meant to be comprehensive or to replace the modeling conducted by DESC. Instead, it is meant to show how the overly conservative assumptions and incorrect modeling approaches used by DESC are leaving value on the table and resulting in a more costly plan for DESC ratepayers. These alternative portfolios show that there is opportunity to avoid expensive ELG retrofits, mitigate transmission upgrade costs, reduce exposure to volatile fossil fuel prices, and maintain reliability while saving ratepayer money.

Q: Why did you think it was necessary to conduct your own modeling and analysis?

A: As explained previously in this testimony, there are several areas where DESC's modeling used incorrect or extremely conservative assumptions that overly favor new gas generation builds. In addition to issues with those underlying assumptions, DESC continued to not evaluate a non-fossil fuel replacement build plan for Wateree and Williams, despite persistent requests from stakeholders. This unnecessarily delays the coal plant retirements and presents the least cost portfolio options as requiring a gas replacement for Williams. The alternative portfolios I presented in this testimony provide the Commission with several non-fossil fuel replacement options and show how they are cost effective and ensure near term reliability.

Q: What methodologies and software tools did you use for the modeling?

A: To the extent possible, I utilized the same methodology as DESC to test alternative resource portfolios, with limited changes to inputs and assumptions to make for a direct comparison. I utilized both PLEXOS long-term (LT) capacity expansion runs and short-term (ST) chronological, 8,670 hour per year, production cost simulations to quantify total generation costs of each portfolio. Similar to DESC, the production cost simulations quantify fuel costs, variable operations and maintenance costs, startup costs, emissions costs, and fixed operations and maintenance costs for each portfolio. I then utilized the same workbooks as DESC to calculate the net present value (NPV) of each portfolio.

Like DESC, I also used the PLEXOS modeling software for my analysis and started from the same database provided by DESC, ensuring that all assumptions other than the ones noted were consistent with DESC modeling. I would like to thank DESC for its transparency in providing data and its modeling files, which allowed me to conduct my independent review of its system modeling. To ensure a valid comparison to the DESC portfolios, I also reran DESC's preferred portfolio using the same revised capital cost assumptions to serve as a reference case for alternative portfolios to be compared against.

Q: Can you provide a discussion and summary table of the portfolios you evaluated in your analysis?

A: For my modeling efforts, I focused on four cases, all based on the DESC preferred portfolio. These scenarios all use DESC's reference load, medium fuel and medium CO_2 forecasts. Two coal retirement options were evaluated: one that considered a 2029 retirement of Williams to avoid $90 million of ELG retrofits, and one that maintains DESC's assumed coal retirement timeline and ELG retrofits.

The final portfolio, referred to as the "Enhanced Reliability Portfolio," was designed to provide additional reliability benefits after the Williams and Wateree retirements. This portfolio was developed to show how reduced costs of the non-fossil fuel retirement scenarios could be reinvested to enhance reliability and to ameliorate concerns that may arise because the storage ELCC was extrapolated beyond the values calculated in the PRM and ELCC Study and insufficiently addressed resources beyond 4-hour storage and at high penetrations. This was done by substituting some 4-hour battery storage to 8-hour battery storage and with additional energy efficiency to reduce load. The additional reliability was achieved by substituting some 4-hour battery storage with 8-hour battery storage and relying on additional energy efficiency to reduce load. The revised energy efficiency assumption uses the reference efficiencies embedded in DESC's reference load and additional savings attributed to greater program deployment and a focus on the highest impact areas. Additional energy efficiency can reduce fuel costs, defer new capacity, and improve reliability. Details about the development of the additional energy efficiency for the Enhanced Reliability Portfolio can be found in Mr. Jim Grevatt's direct testimony.

A summary of the four cases evaluated is provided in Table 4.

Table 4. Alternative Modeling Case Descriptions

Alternative Portfolios	Case Description
DESC Preferred Plan	Consistent with DESC's preferred plan, but implements changes in IRA bonus credits, switches solar build cost to PPA pricing, and fixed financial assumptions for battery storage to allow for a consistent comparison between DESC's Preferred Plan and Alternative Plans.
Alternative Plan 2029 Coal Retirements "Alt Coal, 2029"	Implements the changes listed in Table 5, and shows a non-fossil fuel replacement portfolio necessary to retire Wateree and Williams by 2029, avoiding the ELG retrofits.
Alternative Plan 2031 Coal Retirements "Alt Coal, 2031"	Uses similar assumptions in the Alt Coal, 2029 case above, but adjusts the Williams coal retirement date to 12/31/2030 to be consistent with DESC's timeline. This case includes the ELG retrofits cost at Williams.
Alternative Plan 2029 Coal Retirements + Enhanced Reliability "Alt Coal, 2029 + ER"	The same as the Alt Coal, 2029 portfolio, but with additional measures to enhance system reliability via increased energy efficiency measures and a shift of 400 MW of 4-hr storage to 8-hr storage in 2029. This portfolio is designed to avoid concerns over the storage ELCCs that were extrapolated beyond the values calculated in the ELCC Study.

Q: Can you provide a table of the specific inputs and assumptions you changed in your analysis?

A: Yes. The following table describes the specific inputs and assumptions that were changed in my analysis and compares them to the default assumptions used by DESC. Details on why these assumptions were adjusted can be found in Section 2 of my testimony. In some cases, DESC's preferred portfolio was adjusted to allow for direct comparison with the alternative portfolios as I did not want different assumptions on resource costs to lead to changes in portfolio NPV.

Table 5. Alternative Assumptions by Portfolio

Major Assumptions	DESC Preferred Plan	DESC Preferred Plan, Adjusted for Comparison	Alternative Portfolios
Annual Solar Limit	300 MW/yr	300 MW/yr	600 - 750 MW/yr
Total Solar Build Limit	5,025 MW	5,025 MW	7,500 MW
Solar cost assumptions	50/50 PPA/Utility Cost	PPA only	PPA only
50% ELCC 4-hr Storage Availability[77]	Constrained to >2036	Constrained to >2036	Available in 2026
600 MW 8-hr Storage Availability	None	None	Available in 2026
85% ELCC 4-hr Storage FO&M Cost[78]	Used incorrect 8-hr storage value	Corrected to 4-hr	Corrected to 4-hr
4-hr Storage WACC	14.55% (Incorrect ELG WACC)[79]	13.12% (DESC 25-yr BESS WACC)	13.12% (DESC 25-yr BESS WACC)
Battery storage life	20-years	25-years	25-years
IRA 2026-2036 bonus credits for energy communities	None	1,200 MW 10% solar bonus. All storage 10% bonus	1,200 MW 10% solar bonus. All storage 10% bonus
Thermal Heat Rates[80]	Incorrect LHV	Corrected for HHV	Corrected for HHV
Existing CC Operating Constraints	12/24 hr Up & 24/48 hr Down	6 hr Up & 8 hr Down	6 hr Up & 8 hr Down
New CT Operating Constraints	2 hr Up & 4 hr Down	1 hr Up & 1 hr Down	1 hr Up & 1 hr Down
Available New Thermal Units	2x1 shared only in 2031 & Frame CTs	2x1 shared only in 2031 & Frame CTs	2x1 shared CC available 2031+ & Frame CTs

[77] DESC response to Sierra Club 3-3, attached as Exhibit DS-07.
[78] DESC response to Sierra Club 3-4, attached as Exhibit DS-15.
[79] Id.
[80] DESC response to Sierra Club 3-5, attached as Exhibit DS-12.

Planning Horizon	Single 28-year block	Single 28-year block	Four 7-year blocks with rolling horizon[81]
Chronology Fitting	Partial	Partial	Fitted[79]

Recognizing that the shared resource may not be an available option to DESC after 2031, depending on Santee Cooper's needs, I opted to assess only the CT options for the portfolios presented in the following sections. It should be noted that by removing the shared CC option and instead using smaller CTs, the alternative portfolios are marginally more expensive, but still lower cost compared to DESC's preferred plan.

Q: What are the results of the alternative portfolio analysis?

A: The following table and figures show the results of the alternative portfolios for the 2031 year. 2031 was used in the comparison because it is a critical year in DESCs plan for retiring the Williams coal plant. Annual reserve margin and build plans by resource type can be found in Exhibit DS-16. The results show that, if the changes proposed in Table 6 are implemented, no new gas resources are selected by the model when replacing Williams and Wateree.

Table 6. Cumulative Capacity Builds by Type (MW), 2031

Resource Type	DESC Preferred	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 Enhanced Reliability

[81] PLEXOS allows for different methods to solve capacity expansion problems with benefits to solving problems with many resource options over a long period of time. A rolling horizon allows the optimization problem to see past build decisions and future build limits while resolving smaller planning periods to improve model performance. Using a fitted chronology better represents the chronological (hour to hour) operations and captures the value that solar plus storage resources bring to the system. DESC used a partial approach which does not adequately maintain chronology.

Coal	-1,294	-1,294	-1,294	-1,294
CC	662	0	0	0
Solar	1,624	4,099	3,649	4,099
4-hr Batteries	400	900	900	500
8-hr Batteries	0	200	200	600
Demand Response	77	77	77	77
Total Net Capacity Builds	**1,502**	**4,015**	**3,565**	**4,015**
Total Net Firm Capacity Builds	**-112**	**-233**	**-235**	**-138**

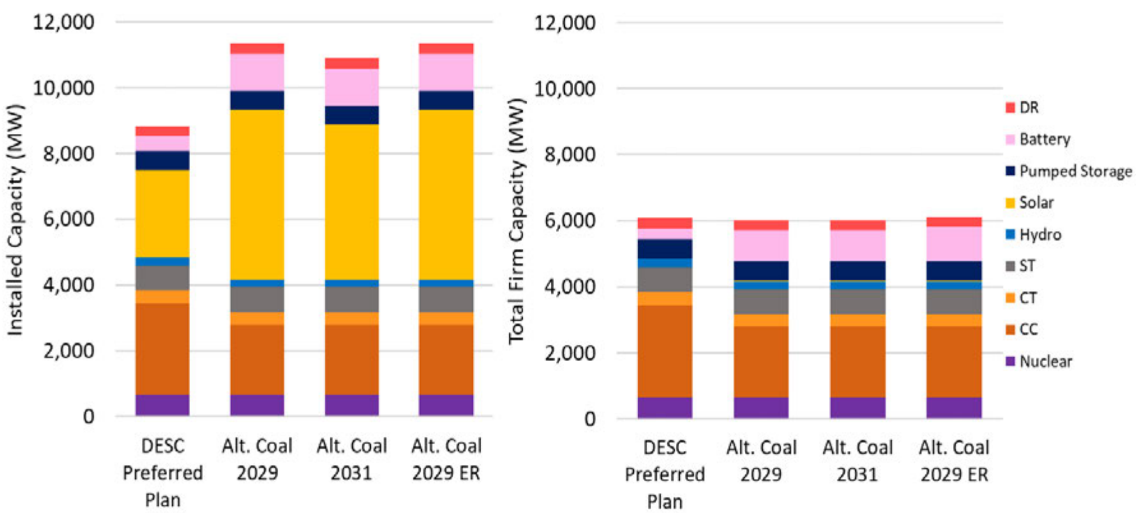
It is important to reiterate that in response to 2022 IRP comments, DESC made the incorrect assertion that stakeholders "request that the Commission order the Company to submit a Build Plan that consists of 100% clean energy resources."[82] That is simply not true. In actuality, stakeholders regularly requested DESC to evaluate a solar and storage replacement portfolio for the two coal plants like the ones provided in Table 6, Figure 2 below graphically displays the capacity mix under DESC's preferred plan and under each alternative portfolio. This figure shows that DESC, , under all the alternative portfolios, would continue to have a large amount of dispatchable fossil fuel units after retirement of coal units.

My analysis below also shows that the alternative portfolios would reduce costs, get DESC on track to meet the Dominion Energy corporate net zero by 2050

[82] Docket No. 2022-9-E, DESC response to the Joint Comments on Dominion Energy South Carolina, Inc.'s 2022 IRP Update at 3 (Feb. 20, 2023).

pledge,[83] and guard against volatile fuel prices and exposure to increased regulatory risks.

Figure 2. 2031 Total Installed Capacity (Left) and Total Firm Capacity by Type (Right)

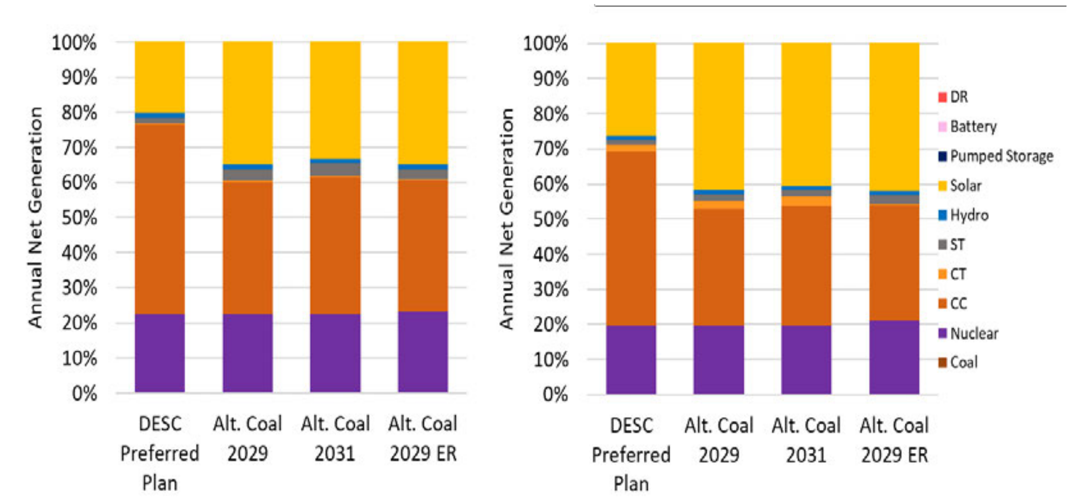


Q: Can you summarize the generation by fuel type and emissions for a few select years?

A: Figure 3 shows the total net generation by resource type for 2031 and 2040. For 2031, the alternative portfolios presented here result in a more diversified portfolio where solar and gas each provide 35-40% of annual net generation. This is an important benefit as it reduces overreliance on gas generation to serve demand, providing certainty to the cost of energy and mitigating exposure to increasing fuel prices over the planning horizon. In DESC's preferred portfolio, gas generation accounts for almost *60% of all generation* in 2031; even in 2050, solar generation accounts for 27% of annual generation and gas generation still accounts for 63%.

[83] Dominion Energy Climate Report 2022, at 6, available at: https://www.dominionenergy.com/-/media/pdfs/global/company/esg/2022-climate-report.pdf

Figure 3. 2031 Net Generation (Left) and 2040 Net Generation by Type (Right)



Due to the increase in net generation from solar, the total emissions, as shown in Table 7, between the alternative portfolios offer reduced greenhouse gas emissions relative to the preferred DESC plan, further reducing risks of increased costs associated with greenhouse gas regulations that may emerge over the coming years as the country looks to reach its net zero by 2050 emissions goals. Compared to 2023 CO_2 emissions, the alternative portfolios show an annual emissions reduction of 46-51% versus 36% for DESC's preferred plan.

More importantly, while emissions across all portfolios rise relative to the 2031 reduction due to increased load growth, DESC's decision in its preferred plan to add substantial levels of new fossil fuels only achieves an 18% reduction relative to 2023 levels. The alternative plans have a more robust decarbonization pathway and achieve a 28-34% reduction in 2050 CO_2 emissions relative to 2023. The results of the alternative portfolio with increased energy efficiency and demand side management show that a more comprehensive planning approach that does not solely rely on supply side solutions to decarbonization, can offer substantially more emissions benefits while achieving a lower cost portfolio.

Table 7. Portfolio CO_2 emissions in thousand tons/yr relative to 2023

Year	DESC Preferred Plan	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 + Enhanced Reliability
2023	9,500	9,500	9,500	9,500
2031	6,100 (**-36%**)	4,870 (**-49%**)	5,030 (**-46%**)	6,830 (**-53%**)
2040	6,620 (**-30%**)	5,090 (**-47%**)	5,210 (**-45%**)	6,830 (**-53%**)
2050	7,830 (**-18%**)	4,450 (**-28%**)	4,410 (**-28%**)	6,270 (**-34%**)

*values rounded to the nearest 1,000 tons

Q: How did the costs of the portfolios compare to one another?

A: I used the same revenue requirements workbooks developed by DESC to calculate the levelized net present value calculations to compare portfolio costs against each other. To maintain a fair comparison between DESC assumptions and the adjusted assumptions outlined above, only the DESC adjusted portfolio and the alternative portfolios are compared in the table below. These results show that the alternative coal retirement plans are considerably lower cost than the DESC preferred plan, saving ratepayers between $31 million and $33 million over the IRP horizon. This is true even after reducing DESC's portfolio cost due to IRA bonus credits and before considering potential savings from deferred transmission upgrades.

Understanding the importance of reliability to DESC, their customers, and the Commission, the Enhanced Reliability Portfolio was designed to keep costs similar, but slightly lower than DESC's preferred plan, by increasing storage duration and energy efficiency to further improve reliability. In this portfolio savings were $4.7 million before accounting for additional savings from avoided transmission upgrades.

Table 8. Comparison of Levelized Net Present Value by Portfolio

LNPV Component	DESC Preferred Plan	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 Enhanced Reliability
Total Variable	$868,058	$772,933	$782,919	$704,729
Total Fixed	$618,995	$580,794	$596,809	$657,850
Total New Build	$338,466	$438,437	$414,575	$458,167
Total LNPV	**$1,825,519**	**$1,792,163 (-1.83%)**	**$1,794,303 (-1.71%)**	**$1,820,746 (-0.26%)**

*values shown in thousands of dollars

Equally important to the *total* cost reductions is the *type* of cost reductions. In the DESC preferred plan, variable costs (fuel and variable O&M) account for 48% of the total NPV, and fixed costs account for 52%. In the alternative portfolios, costs shift from variable costs to fixed costs and new build costs; specifically, for the alternative portfolios variable costs range from 39-44%, fixed costs from 32-36%, and new build costs from 23-25%. The alternative portfolios therefore shift costs from unknown and volatile fuel costs to known and fixed capital costs for new equipment which is "locked-in" once the project is built or contracted. As a result, the alternative portfolios are more resistant to fuel price volatility and unknown market pressure when compared to DESC's preferred plan.

Q: How would the cost comparisons change if you reduced the TIA costs because the alternative portfolios do not have the large combined cycle build and the associated transmission upgrade costs?

A: In addition to the cost comparisons highlighted above, the alternative portfolios may also considerably reduce transmission upgrade costs. By strategically siting a 300 MW 4-hr battery at the Williams site, approximately $100 million dollars of transmission upgrade costs can be deferred.[84]

While this TIA Phase 2 scenario assessed by DESC, at the request of stakeholders, showed substantial savings from deferred transmission, it was not the exact case that stakeholders asked for. I, and other stakeholders, repeatedly asked DESC to assess a scenario where 1) battery storage was sized similarly to the Williams coal plant, and 2) new generation at Canadys would not exceed the current available transmission interconnection, and thereby quantify additional transmission upgrade savings. As discussed previously, it is still unclear how much of the TIA costs DESC assumed are based on the Williams retirement versus the transmission upgrades required for a large combined cycle plant sited at Canadys. Much of the remaining $200 million is likely attributed to DESC's assumption of an oversized gas plant at Canadys, which could also be avoided in a non-fossil fuel replacement portfolio. To assess the potential cost reductions of deferred transmission, Table 9 quantifies the LNPV when reducing the $309 million transmission upgrade costs by $100 million (assuming at least 300 MW of storage is sited at Williams) and deferring them all together (assuming no upgrades are required at Canadys).

[84] *See* Exhibit DS-14 (DESC response to Sierra Club 1-6).

Table 9. Comparison of Levelized Net Present and Avoided TIA Costs

LNPV Component	DESC Preferred Plan	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 Enhanced Reliability
Total LNPV - $309 million TIA	$1,825,519	$1,791,016 (-**1.89%)**	$1,794,303 (-**1.71%)**	$1,820,746 (-**0.26%)**
Total LNPV - $209 million TIA	$1,817,436 (-**0.44%)**	$1,781,824 (-**2.39%)**	$1,786,220 (-**2.15%)**	$1,811,870 (-**0.75%)**
Total LNPV - Deferred TIA	$1,800,542 (-**1.37%)**	$1,762,612 (-**3.45%)**	$1,769,326 (-**3.08%)**	$1,792,343 (-**1.82%)**

*values shown in thousands of dollars

While the exact cost of potential transmission upgrades in the alternative portfolio is unknown, this analysis illustrates the potential benefits of strategically battery energy storage resources within the Charleston load pocket.

Q: Can you provide more explanation as to why the non-fossil fuel replacement portfolio was lower cost than DESC's preferred plan?

A: The non-fossil fuel replacement portfolios accomplish lower costs by maximizing the benefits of the IRA and not arbitrarily limiting the deployment of zero emission resources over the study period. The IRA fundamentally improves the relative economics of solar and storage and offers DESC many opportunities to strategically site resources across its territory to earn bonus credits. These credits further reduce costs and provide benefits to communities with increased tax revenue, jobs, and reduced pollution. By proactively planning for, and not constraining, significant amounts of both solar and battery storage resources to be built during the IRA period, DESC defers investment in near term large new thermal resources and transmission while maintaining reliability.

Q: Are there additional opportunities for cost savings in the non-fossil fuel replacement portfolio?

A: There are additional cost savings for a non-fossil fuel replacement portfolio that were not assessed in my plans. These include the potential to receive additional tax credits via the domestic content bonus credit. If clean energy resources are sourced from domestic manufacturers, an additional 10% bonus to the tax credits is available.

Q: Based on these results, what is your preferred plan?

A: Any one of my alternative portfolios offer a reasonable and prudent path forward and are lower cost and lower risk options compared to DESC's preferred portfolio. My analysis is consistent with previous analyses conducted by DESC, which show that retiring both Wateree and Williams by 2029 and replacing them with solar and storage resources is a cost effective plan and would save ratepayers $90 million in ELG costs and, at a minimum, $100 million in transmission costs. Including the IRA energy community bonus credits and investing heavily in solar and storage resources in the near term allows for a flexible portfolio to be developed.

This approach not only reduces costs, but it is better suited to meet load growth as it materializes with modular resources that can be scaled up or down based on the actual pace of electrification. In other words, it avoids potential pitfalls in overbuilding capacity if load growth does not materialize as has been the case in other recent DESC procurements.

Contrary to DESC's reply comments in the 2022 IRP Update, my preferred portfolio still uses significant quantities of existing firm, dispatchable resources and selects additional firm resources later in the study horizon (2038 or later) to maintain reliability.[85] However, it recognizes that the question of what those future firm resources look like does not need to be answered today and allows time for additional firm non-fossil fuel resources to be developed in the next ten years.

Recognizing the importance of reliability to DESC, their customers, and the Commission, I also recommend a portfolio that was similar in cost to DESC's preferred plan but invested more in longer duration (8-hour) battery storage and increased investment in energy efficiency measures. While this portfolio is not the lowest cost of the alternative plans (though still lower cost than DESC's preferred plan), it would yield improved system reliability while investing in beneficial reliability resources that can be used in future years.

V. RELIABILITY CONSIDERATIONS FOR ALTERNATIVE PORTFOLIOS

Q: Can the alternative portfolios evaluated in your modeling be reliable?

A: Yes, a portfolio of solar and storage resources can reliably be used to replace coal capacity. Determining how much solar and storage capacity must be added to replace retiring coal capacity is done through capacity accreditation. The goal of capacity accreditation is to measure effective capacity, in a technology-agnostic manner, and create a reliability-neutral exchange rate between resource types. Rather than comparing installed capacity of resources, it is important to compare *effective capacity* for resource adequacy, in this case using ELCC.

[85] See Docket No. 2022-9-E, DESC Reply to the Comments of Sierra Club and Joint Intervenors to 2022 IRP Update, at 3 (Feb. 20, 2023).

In the alternative portfolios discussed previously, I used the ELCC curves generated in the DESC PRM and ELCC Study and followed DESC's conservative assumption that additional storage (beyond the values calculated in the study) dropped to 50% ELCC. In doing so, I confirmed that the planning reserve margin was achieved throughout the forecast horizon. Understanding that ELCC is highly dependent on the underlying resource mix and load profile, the Enhanced Reliability Portfolio was developed to mitigate the uncertainty associated with storage additions beyond the levels considered in the original PRM and ELCC Study.

It should be noted that the alternative portfolios proposed do not use solar and storage exclusively to meet reliability needs or replace the retiring Williams and Wateree coal plants. Instead, the portfolio, in its entirety, is designed to meet system reliability. I want to be clear that my testimony, in no way, proposes a portfolio that "can operate solely on intermittent resources without reliable, dispatchable resources[86]" as stated in DESC's reply to the Joint Comments on DESC's 2022 IRP Update. Existing nuclear, gas, hydro, pumped storage, solar, and demand side resources, along with new solar and storage resources can be used in combination to meet the reliability needs of the system.

In addition, the alternative portfolios do rely on additional firm capacity additions in future years (appearing in 2038 or later). This affords time for technological advancement for new firm resources like long-duration storage or

[86] See Docket No. 2022-9-E, DESC Reply to the Comments of Sierra Club and Joint Intervenors to 2022 IRP Update, at 2 (Feb. 20, 2023).

zero carbon fuels to be developed and for load flexibility programs to improve to provide similar services to those provided by combustion turbines in DESC's preferred portfolio.

Q: Can you discuss the reliability risks associated with weather-dependent outages and fuel supply constraints?

A: Unlike solar and storage resources, DESC is assigning 100% firm capacity credit for thermal generators in its portfolio, accrediting the units entire capacity towards the reserve margin requirement. This includes the new shared combined cycle and other combustion turbines in the future build plan. However, there is no such thing as perfect capacity, and:

> different resources bring different capabilities. Battery energy storage may be well suited to solve frequent, short-duration shortages, while demand response may be better suited for infrequent, but challenging, events. Additional resources like long-duration storage, hydro, and thermal generation may be required for long-duration capacity shortages spanning days or weeks. However, gas plants are not always available on demand, as they experience planned as well as weather-related outages. The false dichotomy between the perfect resource and resources with only partial 'firm capacity' is due to be replaced by analysis applying the effective load carrying capability (ELCC) metric to all resource types.[87]

In DESC's analysis, however, the risk of gas generator outages is only accounted for in the planning reserve margin and is not assigned to specific generators. As a result, there is no apples-to-apples comparison between new candidate resource types for the reliability contributions they provide: new gas

[87] Energy Systems Integration Group. 2021. *Redefining Resource Adequacy for Modern Power Systems. A Report of the Redefining Resource Adequacy Task Force*, at 18. https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf

resources are counted as 100% firm capacity resources while battery storage is discounted by an ELCC.

This approach has been rejected in other jurisdictions. A recent statement from FERC Commissioner Clements stated that this type of capacity accreditation structure is "unduly discriminatory because it reduces the capacity accreditation of wind and solar [and storage] resources based on historically demonstrated performance, while failing to account in any way for non-performance of other resource types."[88] Capacity accreditation can and should be used for all types of resources in a consistent manner.[89]

This is perhaps most acute during extreme winter weather where cold snaps increase equipment failure and power plant outages,[90] and competing uses for natural gas in heating demand can cause fuel supply constraints across the pipeline network. These circumstances can lead to correlated outages of the underlying thermal fleet, causing multiple generators to be unavailable at the same time, precisely when they are needed most for reliability.

Q: Have you observed this reliability challenge in DESC's service territory?

A: Yes, Winter Storm Elliott was a perfect example of this risk. According to DESC,

> [i]n the early morning of December 24, 2022, DESC lost generation resources at various times due to factors that in some cases were

[88] FERC, *Commissioner Clements' Concurrence on Rehearing of Southwest Power Pool's ELCC Capacity Accreditation Proposal,* March 2, 2023, Docket Nos. ER22-379-003, ER22-379-004, https://www.ferc.gov/news-events/news/commissioner-clements-concurrence-rehearing-southwest-power-pools-elcc-capacity

[89] Energy Systems Integration Group. 2023. *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation*. A Report of the Redefining Resource Adequacy Task Force. https://www.esig.energy/new-design-principles-for-capacity-accreditation.

[90] Murphy, S., and Lavin, L., *Resource adequacy implications of temperature-dependent electric generator availability*, Applied Energy, Vol 262, March 2020 https://www.sciencedirect.com/science/article/pii/S0306261919321117

> related to the weather directly and in others were not. Support was not available from neighboring utilities who were engaged in load shedding or otherwise in an emergency posture at that time. To maintain operating reserves, DESC was required to curtail firm off-system sales, impose voltage limitations, and impose a brief curtailment of firm load on the morning of December 24, 2022. Service to all customers was restored within minutes and no further load shedding was required.[91]

On December 24 and 25th, the following DESC units were unavailable to serve load for some portion of the days:[92]

Table 10. DESC Generator Outages on December 24 and 25th, 2022

Unit Name	Outage Type
Columbia Energy Unit:1	Forced Outage
Columbia Energy Unit:2	Forced Outage
Columbia Energy Unit:3	Forced Outage
Hagood - GT 4	Forced Outage
Jasper Unit:1	Forced Outage
Jasper Unit:4	Forced Derate
Parr - GT 3	Forced Outage
Urquhart Unit:2	Forced Outage
Urquhart Unit:6	Forced Outage
Urquhart Unit:6	Forced Outage
Wateree Unit:1	Forced Outage
Wateree Unit:2	Forced Outage

A review of generator performance is provided in Mr. Delk's direct testimony in Docket No. 2023-2-E, where he attempts to explain that many of these

[91] DESC 2023 Integrated Resource Plan at 12.

[92] DESC response to SACE/CCL 1-4, attached as Exhibit DS-17.

outages were purely mechanical in nature and not related to weather conditions. This is highly misleading. It is no coincidence that twelve of DESC's generators all went on a systemic, correlated, forced outage when South Carolina was facing extreme cold temperatures and fuel supply constraints.

According to Mr. Delk:

> During Winter Storm Elliott, one of the combined-cycle blocks at Urquhart Station experienced a non-weather-related issue. Combustion turbine Unit 6 and steam turbine Unit 2 tripped offline just after midnight on December 24. Unit 6 had been operating reliably for several hours on fuel oil (***due to natural gas pipeline operational limitations***), when the unit tripped offline due to a malfunction of the combustion turbine unit's fuel oil-firing system. This failure was not due to cold ambient temperatures. It was purely mechanical in nature.[93]

To clarify, the generator would not have been required to run on fuel oil at all had it not been for cold temperatures and fuel supply limitations (i.e. fuel supply constraints are weather-driven based on increased gas needs for both the power sector and heating demand). In another misleading statement, DESC stated that "[n]o units were unavailable due to lack of natural gas fuel supply for the period in question,"[94] which is clearly contradicted by Mr. Delk's testimony.

Columbia Energy Center also had reliability problems, when "[a]ll three units at CEC experienced weather-related issues with heat tracing systems in the early morning hours of December 24, 2022" and "excessive power demands on various heat tracing elements overloaded the electrical circuits that supply them."[95] When weather dependent outages from 2014 were raised by stakeholders

[93] Direct Testimony of Henry E. Delk, on behalf of Dominion Energy South Carolina, Inc. at 20-21, emphasis added.
[94] *See* Exhibit DS-X7 (DESC response to SACE/CCL 1-4).
[95] Direct Testimony of Henry E. Delk, on behalf of Dominion Energy South Carolina, Inc. at 21.

previously, DESC staff suggested that it was no longer an issue at CEC because of winterization efforts at the plant. Similar challenges were experienced at Wateree Unit 1 and 2.

But, regardless of the cause, it is undeniable that there were correlated outages during Winter Storm Elliot across the DESC fleet on both coal and gas generators *at exactly the time* they were needed most due to high peak winter demand. This risk of correlated, weather dependent outages, is one of the most significant, unaccounted for risks in DESC's system, and will only be amplified with an addition of a large shared combined cycle resource. However, DESC's reserve margin analysis, which treats all thermal capacity at 100% rating towards the reserve margin, ignores this major threat to reliability.

Q: How are other utilities and system operators addressing this risk?

A: Capacity accreditation for all resources—including gas and coal—is being instituted across the country. ISONE,[96] NYISO,[97] and PJM's[98] capacity market design and resource accreditation is being applied to all resource types in one way or another, and specifically incorporating weather dependent outage risk and fuel supply constraints. These system operators are incorporating this change so that generators can be measured consistently and fairly in capacity markets.

[96] ISO New England, *Resource Capacity Accreditation in the Forward Capacity Market, Winter Gas Modeling and Accreditation,* NEPOOL Markets Committee, April 11, 2023, https://www.iso-ne.com/static-assets/documents/2023/04/a05a_mc_2023_04_11-13_rca_gas_accreditation.pptx

[97] NYISO, *Capacity Accreditation: Implementation Details,* Business Issues Committee, 12/14/2022, https://www.nyiso.com/documents/20142/34963268/4%20CA%20Capacity%20Accreditation%20pres.pdf

[98] PJM, *Critical Issues Fast Path - Resource Adequacy,* https://www.pjm.com/committees-and-groups/cifp-ra

In DESC's case there is no capacity market, so it is not necessary to apply ELCC (or alternative accreditation) to all resources, but it is critical to apply it consistently across new resource candidates so that different resources can be compared against one another in a consistent manner. It is also important to understand the reliability contributions of retiring coal plants, Williams and Wateree, to understand how much *effective capacity* is required to replace those generators with comparable reliability. Alternatively, DESC can and should back check the reliability of resulting portfolios via "round-trip" analysis with probabilistic resource adequacy analysis as I suggested earlier in my testimony.

In sum, I recommend that the Commission require DESC to calculate ELCC for the Williams, Wateree, and new combined cycle and combustion turbine resources in a similar and consistent manner as solar and storage resources.

Q: How can interregional transmission and market transactions support reliability and reduce costs?

A: Another option for mitigating this risk is with interregional transmission. By incorporating interregional transmission in the planning process and considering new transmission to neighboring regions, DESC can better capture the benefits of geographic diversity in load and renewable resources. Adding new gas resources can only improve reliability if fuel supply is available and the generators are not affected by weather dependent outages. Interregional transmission, however, can access resources located in regions that are not affected by the extreme weather. Currently DESC's IRP PLEXOS model only models market interactions via a simplified import/export generator in early years of the horizon and shuts off all market transactions in later study years. This simplified approach also does not represent the full capability of DESC to import power from neighboring regions, understating the benefits of market transactions.

Furthermore, according to a recent Brattle report conducted for the South Carolina General Assembly, wholesale market reforms with neighboring utilities and/or RTOs could save annual net benefits of $280 million to $362 million for South Carolina ratepayers.[99]

VI. RECOMMENDATIONS FOR THE COMMISSION AND THE COMPANY

Q: Please summarize your recommendations for the Commission.

A: I recommend that the Commission reject the DESC IRP and determine that the preferred plan is not the most reasonable and prudent for ratepayers. The Commission shouldrequire DESC to make revisions to its modeling inputs and assumptions that are outlined below. While DESC claims that their portfolio has generation diversity because they limited solar additions, gas is by far the largest single fuel source, representing nearly 60% of energy in 2031 and nearly three times larger than the share of solar energy as a percentage of generation.

The Commission should therefore consider alternatives to the shared combined cycle resource proposed to replace Williams and order DESC to consider non-fossil fuel replacement options. This approach would reduce cost for

[99] Tsoukalis, et al., *Assessment of Potential Market Reforms for South Carolina's Electricity Sector*, The Brattle Group, April 17, 2023, https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf

ratepayers, mitigate fuel price volatility and winter supply constraints, and ensure that DESC is fully capturing federal tax incentives. The IRA represents a significant opportunity for DESC to invest in new, clean, and flexible technologies while reducing costs for ratepayers.

I do however, believe that the Commission should accept that the retirement of Williams and Wateree coal plants are reasonable, prudent, and in the best interest of DESC ratepayers. However, given continual delays in planning for the Williams coal plant retirement, the Commission should recognize the wasted expense for the $90 million ELG retrofits that DESC is proposing simply to keep the plant online an additional two years. This demonstrates a troubling lack of long term planning and actions should have been taken earlier to accelerate the coal plant retirement as identified in DESC's preferred plan in the 2020 Modified IRP. As a result, to prevent further delays I recommend that the Commission:

- Reject the IRP as filed and require DESC to correct errors and omissions in this IRP,
- Acknowledge the ELG cost issues related to DESC's delays and recognize DESC's failure to implement a short term action plan to move forward with a battery storage replacement at Wateree and other clean energy resources, despite it being in their preferred plan,
- Direct the Company to move forward with a definitive coal retirement plan by beginning the selection of replacement resources once the IRP modeling error and omissions are correct.

Q: What modifications do you believe should be made to DESC's 2023 IRP?

A: Prior to accepting the IRP, I recommend that the Commission require DESC to update and adjust the following inputs, assumptions, and methodologies to ensure that portfolios are evaluated in a fair, transparent, and accurate manner. The adjustments I recommend to be completed in this IRP include:

- Evaluate at least one coal replacement portfolio that does not include new gas or fossil resources to replace the Williams and Wateree coal plants.
- Evaluate a portfolio with the Wateree and Williams coal plant retirements by end of year 2028, avoiding the ELG costs.
- The impacts of the proposed EPA greenhouse gas rule should be explicitly considered, including strict requirements on coal operating past 2035 and on gas plants (existing and new) starting in 2032.
- Properly incorporate IRA energy community bonus credits for standalone battery storage and some of the potential solar PV additions. DESC should recognize that many locations across South Carolina qualify as energy communities, particularly for battery storage that can be sited at or in close proximity to retired coal plants.
- Remove the arbitrary 50/50 utility self-build and PPA solar resource ratio and use whichever resource candidate is lower cost.
- Increase annual build limits for solar resources and make storage resources available earlier in the model horizon. This will ensure that enough solar and storage candidate resources are available to the PLEXOS model to retire the Williams and Wateree coal plant and not force the addition of a new gas resource.

- Fix the heat rate for new gas resources to reflect higher heating value (HHV) rather than lower heating value (LHV) to be consistent with actual fuel consumption and the model's treatment of existing gas resources.
- Properly assign the TIA transmission upgrade costs based on new gas builds rather than on the coal retirement decision. Because most of these upgrades are due to a proposed plant site at Canadys being 3 times greater than the capacity of the previous plant size, much of the upgrade cost could be avoided by properly siting and sizing a battery storage resource.
- Adjust errors in the battery FO&M and WACC that were identified in my testimony.

Q: What adjustments do you believe should be made in the next IRP update and subsequent full IRPs?

A: While I identified several other problems in the IRP, I recognize that some of these issues will take longer to resolve or require additional feedback from the Commission or stakeholders. As a result, I recommend that the following adjustments be made to future IRP updates and discussed in upcoming IRP stakeholder sessions.

- The capacity accreditation (ELCC) process should be applied to all resources in a consistent, non-discriminatory manner. This includes assigning an ELCC to thermal resources, taking into account the potential for correlated, weather dependent outages and fuel supply constraints. Correlated outages evaluated should be at least as large as the ones experienced in December 2022.

- Solar and storage ELCCs should also be updated in future IRPs and quantified at higher penetration levels so that extrapolation is not required. Additionally, an 8-hr storage ELCC should be determined along with the combined impact to ELCCs after both 4 and 8-hr storage are built. The ELCCs should also be measured on at least two future portfolio years so that the resource portfolio and demand profile is accurately represented.
- Land based wind, offshore wind, and long duration energy storage resources should be included as future candidate resources in the PLEXOS LT simulations, with ELCC values also calculated. This will ensure improved resource diversity for resource adequacy.
- Transmission constraints should also be reflected in the PLEXOS model, either via nodal or zonal topology so that generation and transmission decisions can be considered together.
- Further evaluate interregional transmission and/or regional market opportunities as a way to mitigate reliability risk and reduce cost for ratepayers.

In addition to the proposed changes listed above, moving forward, the Commission should also require DESC to show when, and where, stakeholder feedback was actually implemented in the IRP modeling and analysis.

Q: Do you have any other recommendations for the Commission?

A: Yes. My final recommendation for the Commission is to give DESC clear and unequivocal directives regarding the retirement and replacement of Wateree and Williams. The early coal retirements were identified as a preferred plan by DESC in the 2020 Modified IRP, but no meaningful decisions or actions have been taken since that time to move forward. In the 2020 Modified IRP, DESC stated that "[n]o definitive decisions concerning large new resource procurements are required in the immediate time frame, allowing time for further data collection and study of these alternatives."[100] However, despite the lack of urgency, two years have since passed and DESC has pushed back the earliest feasible retirement date to 2031, forcing costly ELG retrofits at Williams. It is clear that the early retirement of Williams and Wateree is in the best interest of DESC ratepayers and timely decisions and actions must be made to ensure replacement resources can be added in an orderly, and reliable manner. Given the timeline required to bring on new resources, it is imperative that a decision be made on the coal retirements as soon as practicable.

Q: Does this conclude your testimony?

A: Yes.

[100] DESC Modified 2020 IRP at 77, (Dkt 2019-226-E).

Exhibit DS-01

Resume of Derek Stenclik

TELOS ENERGY

Derek P. Stenclik

Founding Partner

Saratoga Springs, NY

M.S. Applied Economics & Management, Cornell University
B.A. International Relations, State University of New York at Geneseo

Derek Stenclik is a founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has over a decade of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration. He is a recognized expert on wind, solar, and battery integration, resource adequacy, and grid planning. He is passionate about guiding the development of the future power grid, accelerating renewable energy adoption, and ensuring reliability.

Derek combines economic and engineering principles to bring a balanced perspective towards the opportunities and challenges of our current and future energy mix. He recognizes the role of a diverse resource mix and understands the need to balance affordability, reliability, and sustainability. He provides his clients unbiased, technical, and quantitative analysis by leveraging detailed power system models and simulations.

He regularly contributes to industry forums, including IEEE, CIGRE, ESIG, and peer-reviewed publications. He has authored over a dozen peer-reviewed articles and given numerous talks related to renewable integration, resource adequacy, energy storage, and ancillary market design.

Prior to founding Telos Energy, Derek spent eight years in GE Power's Energy Consulting department, most recently as the Senior Manager of Power System Strategy. In that role he supported global clients across the energy industry, including utilities, grid operators, developers, equity investors, and NGOs. He also provided power market expertise across GE's portfolio of businesses, including the GE Power, Renewables and Capital divisions.

Derek graduated with an M.S. degree in Applied Economics and Management from Cornell University, with a concentration in Environmental and Natural Resource Economics. He also holds a B.A. in International Relations from the State University of New York, College at Geneseo, where he graduated Phi Beta Kappa and Summa Cum Laude.

Derek P. Stenclik

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SHORT BIO

Derek Stenclik is a co-founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has nearly a decade of experience helping clients across the electric power industry navigate evolving markets and accelerate clean energy integration.

EXPERIENCE

2019-Present — Founding Partner, *Telos Energy*

- Lead business development, marketing, and finance initiatives
- Consult global clients in the electric power industry

2015-2019 — Senior Engagement Manager, *GE Energy Consulting*

- Supported utilities, grid operators, developers, governments, and NGOs
- Managed a diverse team of 11 power systems engineers and consultants

2011-2015 — Consultant & Senior Consultant, *GE Energy Consulting*

2010-2011 — Energy Analyst Intern, Office of Climate Change
New York State Energy Research and Development Authority
New York State Department of Environmental Conservation

EDUCATION

Aug. 2011 — M.S. Applied Economics & Management, *Cornell University*

- Concentration: Environmental and Natural Resource Economics
- Thesis: *Understanding Private Forest Owner Participation in Future Carbon Offset Programs in the Catskills Region: A Contingent Valuation Approach.*

May 2009 — B.A. International Relations, State University of New York at Geneseo

- Honors: Phi Beta Kappa, Summa Cum Laude

EXPERTISE

Energy Markets and Power Systems Expertise:

- Economic dispatch and production cost modeling (GE MAPS and PLEXOS software)
- Renewable integration, integrated resource planning, and cost-benefit analysis
- Resource adequacy analysis and reliability planning
- Market design, energy and capacity market forecasting
- Financial proforma analysis, asset valuation, and tax equity investment
- Transmission congestion and curtailment risk analysis

AWARDS

- D. Stenclik, 2019 Excellence Award of the Electric System Integration Group (ESIG) for his work related to advances in PV-battery peaking plants.
- D. Stenclik, 2016 Annual Achievement Award of the Utility Variable-Generation Integration Group for the contribution to the Pan Canadian Wind Integration Study
- M. Richwine, D. Stenclik, 2016 Next Generation Network Paper Competition, 1st Place, CIGRE-US National Committee.

PUBLICATIONS & REPORTS

- **D. Stenclik**, Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation, Energy Systems Integration Group, Feb 2023
- **D. Stenclik**, et al., Beyond Expected Values, Evolving Metrics for Resource Adequacy Assessment, CIGRE Session 2022, Aug 2022.
- **D. Stenclik**, M. Welch, P. Sreedharan, Reliably Reaching California's Clean Electricity Targets, Stress Testing Accelerated 2030 Clean Portfolios,
- **D. Stenclik,** Redefining Resource Adequacy for Modern Power Systems, Energy Systems Integration Group, 2021.
- **D. Stenclik,** et al., Quantifying Risk in an Uncertain Future: The Evolution of Resource Adequacy, IEEE Power & Energy Magazine, Nov/Dec 2021.
- D. Lew, […], **D. Stenclik,** Secrets of Successful Integration, IEEE Power & Energy Magazine, Nov/Dec 2019.
- B. Zhang, **D. Stenclik**, W. Hall, Calculating the Capacity Value and Resource Adequacy of Energy Storage on High Solar Grids, CIGRE-US Grid of the Future, Reston, 2018.
- **D. Stenclik**, B. Zhang, R. Rocheleau, J. Cole, Energy Storage as a Peaker Replacement, IEEE Electrification, Vol. 6 No. 3, 2018.
- **D. Stenclik**, M. Richwine, C. Cox, To Shift or Not to Shift? An Energy Storage Analysis from Hawaii, Hybrid Power Systems Workshop, Tenerife, May 2018.
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- E. Ibanez, B. Daryanian, **D. Stenclik**, Capacity Value of Canadian Wind and the Effects of Decarbonization, 2017 Ninth Annual IEEE Green Technologies Conference (GreenTech), Denver, 2017.
- **D. Stenclik**, P. Denholm, B. Chalamala, Maintaining Balance: The Increasing Role of Energy Storage for Renewable Integration, IEEE Power and Energy Magazine, Volume: 15, Issue: 6, Nov. - Dec. 2017.
- G. de Mijolla, **D. Stenclik**, E. Ibanez, D. Lew, Regional Valuation of Regulating Reserves from Distributed Flexible Resources, CIGRE-US Grid of the Future, Cleveland, 2017.
- M. Richwine, **D. Stenclik**, Analysis of Grid Strength for Inverter-Based Generation Resources on Oahu, CIGRE-US Grid of the Future, Cleveland, 2017.
- M. Richwine, **D. Stenclik**, An Integrated Approach to Analyzing the Impact of Increasing Distributed PV Generation on Dynamic Stability in Oahu, CIGRE-US Grid of the Future, Philadelphia, 2016.
- D. Woodford, B. Daryanian, **D. Stenclik**, M. Salimi, The Way to a TransCanada Electric Transmission System, CIGRE Canada Conference, Vancouver, 2016.

Exhibit DS-02

DESC Response to ORS 1-26

DOMINION ENERGY SOUTH CAROLINA, INC.
SOUTH CAROLINA OFFICE OF REGULATORY STAFF'S
FIRST AND CONTINUING REQUEST FOR PRODUCTION OF
BOOKS, RECORDS, AND OTHER INFORMATION
DOCKET NO. 2023-9-E

REQUEST NO. 1-26:

Regarding CO2:

a. On page 5, provide the workpapers, electronically used to create Figure 1 and include the individual company names of the electric utilities.

b. On page 6, please provide the table used to create Figure 2 regarding DESC's historical CO2 emissions.

c. See page 63, which states "CO2 Emissions and Clean Energy" – Please identify any existing or potential future state and federal CO2 environmental regulations that the Company is complying with or believes it will have to comply with in the future.

d. With the recognition that neither the federal government nor South Carolina have ever passed CO2 legislation, please explain the basis for the Company's expectation that CO2 costs will be imposed one day.

e. See page 22, which states, "Dominion Energy committed itself to achieve interim targets to cut Scope 1 carbon emissions from the power generation business by 55% by 2030 compared to 2005 levels." What influence of any kind did this commitment have on the 2023 IRP?

f. On page 9, what is the Company's basis for stating that the Reference Build Plan's market conditions are the most likely future conditions? For example, why does the Company believe the most likely assumption for CO2 is the Company's Medium CO2 price forecast?

RESPONSE NO. 1-26:

A. DESC did not create the chart on page 5 and therefore, is not in possession of information responsive to this request.

B. See attached spreadsheet "Historical Annual CO2 Emissions 2005 to 2021 Bar Chart.xlsx"

C. Other than EPA's New Source Performance Standards ("NSPS") under 40 CFR Part 60 Subpart TTTT which is a component of permitting any new thermal generation resources in the United States, DESC is unaware of any additional existing or potential state and/or federal CO2 environmental regulations that the Company is required or believes it will be required to comply with in the future.

D. The IRP models zero CO2 cost, medium CO2 cost and high CO2 cost to comply with the requirements of Act No. 62. While there is currently no explicit price on CO2 and the design of future policies is uncertain, the medium level of CO2 assumes that a moderate CO2 price is imposed on the electric sector as a proxy for future policy that increases the cost of fossil-fired resources.

E. None.

F. See answer to D.

PERSON RESPONSIBLE: James Neely

Exhibit DS-03

Sierra Club comments submitted to IRP Stakeholder Session VII Homework

April 7, 2022

DESC Stakeholder Workshops

Session 7: Preliminary Findings Coal Retirement and Reliability Materials

Session 7 Homework: Apr 7, 2022

The answers to the Session 7 Homework questions were developed by Derek Stenclik and Ryan Deyoe of Telos Energy on behalf of the Sierra Club. Sierra Club appreciates this opportunity to provide feedback to the Session 7 Stakeholder Meeting. Engaging stakeholders early in the planning process creates a collaborative environment and ensures that modeling details and assumptions are properly vetted early in the process to allow ample time for revision before the final IRP and retirement study is conducted.

General Feedback

1. What topics should DESC add to the agenda at Session VIII or as part of a future Stakeholder Session?

Sierra Club appreciates the ability to provide recommendations on future Stakeholder Sessions and believe the following topics would benefit from stakeholder input and discussion with DESC:

- ELG Compliance Options: It remains unclear why DESC is assuming Williams cannot retire by 12/31/2028 and avoid the ELG upgrade requirements. We request that in a future stakeholder session DESC clearly discuss the ELG compliance options available to both Williams and Wateree, and discuss any determinations the company has made regarding those options.
- Replacement Resources Selected by PLEXOS LT simulations: While the Stakeholder Session VII provided some preliminary results for the portfolio NPVs, it did not provide any information on selected candidate technologies for replacement. In the next stakeholder session, please provide this information, along with a discussion on why DESC believes each technology was selected (or not selected) by the model.
- Description of model settings for LT simulations: The PLEXOS LT capacity expansion module has numerous settings that can significantly affect the model results. Of particular interest is the model horizon, any splits in the horizon, and how the model is handling chronology and week/day sampling.

- Resource Adequacy, Planning Reserve Margin, and ELCC Modeling Details: Session VII discussed the Reserve Margin Study that will be incorporated into the 2023 IRP. This is a critical study that will determine the planning reserve margin, resource capacity accreditation, and how portfolios are measured for reliability. Due to the importance of this study, we kindly request this be a focal point of the next stakeholder session. Additional comments are provided in the response to the following question.

Reliability Analysis

2. What alternative ELCC values, if any should DESC consider, for replacement resources as part of the PLEXOS resource optimization? Please provide a basis for any proposed estimates?

On page 29 of the Stakeholder Session VII slides, DESC provides ELCC values for solar PV and 4-hour battery storage, but does not provide any information on how these values are selected. Given the incomplete information provided, we provide some initial feedback for the proposed values, but also provide additional comments on ELCC and resource adequacy analysis more generally.

Solar ELCC: 4.25%

We understand that the ELCC of solar has been litigated previously in avoided cost and IRP dockets, so we will not provide recommendations other than reiterating the need to properly reevaluate this in the forthcoming Reserve Margin Study.

While incremental (marginal) additions of solar may have limited reliability benefits because reliability risk is shifted to early winter mornings (before sunrise) and late summer evenings, this does not account for benefits attributed in a system with high amounts of energy storage. At higher levels of thermal unit retirements and increased solar + storage, resource adequacy becomes more *energy constrained* rather than capacity constrained.[1] As a result, solar can provide significant resource adequacy benefits when combined with other resources.[2] In the winter, solar can provide additional energy mid-day to recharge batteries in time for the second peak demand period in the evening. In the summer it reduces and narrows midday peak load and provides energy for batteries to discharge in the evening. Establishing this *portfolio effect* is critical (see figure).

[1] North American Electric Reliability Corporation, *Ensuring Energy Availability with Energy-Constrained Resources*

[2] National Renewable Energy Laboratory, *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States,* https://www.nrel.gov/docs/fy19osti/74184.pdf

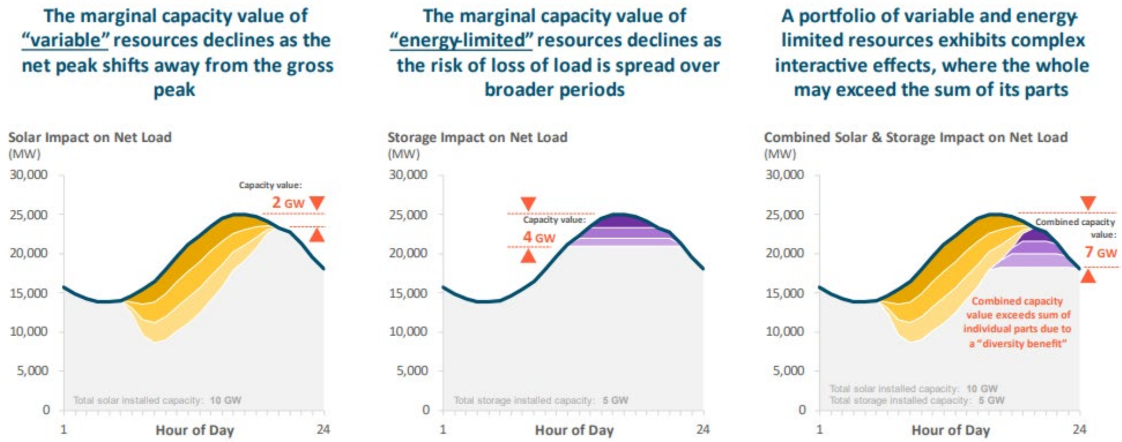

Figure 1: Illustration of the portfolio effect of solar and storage[3]

Battery Storage ELCC: 100% up to 375 MW, 50% afterwards

We agree that DESC should model a saturation effect for battery storage, thus decreasing the ELCC at higher installations. However, this saturation effect is countered by the portfolio effect of adding more solar (see above). As long as solar (or other variable renewable energy) is added in tandem to the storage, battery storage ELCC diminishes much more slowly. For example, in Duke Energy Carolina's 2020 IRP - which evaluated ELCC using SERVM modeling - battery ELCC remains at 86% or above out to 1600 MW.[4] In our experience, 4-hour storage saturation starts to occur between 15-20% of peak load. As a result, we recommend the following ELCC values for storage, until a more robust resource adequacy and ELCC study can be conducted.

Table 1: Recommended Temporary ELCC Values for 4-hour Storage

Installed Capacity (ICAP)	Percentage of Peak Load*	Firm Capacity (UCAP)	Marginal ELCC (% of additions)	Average ELCC (% of total)
750	15%	750	100%	100%
1000	20%	950	80%	95%
1250	25%	1100	60%	88%
1500	30%	1200	40%	80%

*assumes winter peak load of 5000 MW

[3] Energy + Environmental Economics, Resource Adequacy in the Desert Southwest, https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

[4] Astrape Consulting, *Duke Energy Carolinas Storage ELCC Study, 2020,* *https://dms.psc.sc.gov/Attachments/Matter/41d424e5-077b-4ff9-8bb3-3c31467b2638*

In addition, it is also important to provide PLEXOS with an 8-hour storage candidate with 100% ELCC.

We understand the need for DESC to ensure reliability and resource adequacy. Given that the values proposed above are higher than the values proposed by DESC, we recommend ex-post resource adequacy analysis on *resulting* *portfolios to ensure they meet the reliability criteria of 0.1 days per year (or equivalent metric used by DESC). This "round-trip" modeling can identify potential shortfalls or surplus capacity and better design a coal replacement portfolio. It is better to err on the side of higher ELCC values up front, and test with resource adequacy simulations, than it is to potentially overbuild replacement portfolios as this ex-post analysis will ensure portfolio effects are captured.*

CT and CC ELCC: 100%

DESC does not include a proposal for ELCC or equivalent capacity accreditation for thermal resources. This introduces an implicit bias favoring new CT and CC resources. At a minimum, these resources should be discounted by the unforced capacity (UCAP), as is done in many jurisdictions.[5] In addition, these resources should be reduced further due to the probability of correlated outages. Much like the effects of weather on wind and solar, thermal resources are also affected by weather, particularly extreme cold during DESC's winter peak conditions. Gas turbines have reduced output due to ambient conditions, increased forced outage rates due to extreme cold, and fuel supply constraints on the natural gas network. There is no such thing as perfect capacity, and candidate CT and CC resources should be reduced.[6] Advanced Energy Economy and Astrape Consulting recently released a report outlining proper ELCC accreditation for thermal resources.[7]

As a result, we recommend new CT and CC resources have a 90% ELCC for firm capacity until a more detailed ELCC study can be conducted.

Note, discounting thermal units should be done across existing resources as well, however this will require a change to the planning reserve margin and should be evaluated in the planning reserve margin study.

3. How should DESC proceed with using the NREL dataset to estimate solar performance, are there any adjustments or considerations that you recommend?

While the NSRDB data may not be perfect, we believe that the limitations of using historical observations from a select number of plants, as proposed by DESC, is significantly less robust. Using

[5] PJM, *Terminology for ICAP, UCAP, CIRs, and ELCC: Definitions and Functions*, Capacity Capability Senior Task Force, June 22, 2020.

[6] ESIG, *Redefining Resource Adequacy, https://www.esig.energy/resource-adequacy-for-modern-power-systems/*

[7] Advanced Energy Economy, *Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources,* https://www.aee.net/aee-reports/getting-capacity-right-how-current-methods-overvalue-conventional-power-sources

historical observations would provide a short historical sample (as opposed to 23-years provided by the NREL NSRDB), amplify variability because it would not capture geographic diversity, and not be representative of new resource configurations with much higher inverter-loading rations (DC:AC ratios) that increase capacity factors and project economics.

Regarding the measured irradiance data, we request that DESC provide stakeholders with either the full set of historical solar radiation observations taken from KCHS (Charleston International Airport) or direct stakeholders to the source data if it is publicly available.

The reason for this request is that in order to properly assess the observations compared to the NSRDB data stakeholders need to understand the specific instruments and type of weather station involved in collecting the data. Discrepancies between data sources can come from issues in the ground observations or from the satellite derived observations. Regarding the latter, one reason for hesitancy in dismissing the NSRDB data is that this data undergoes validation using satellite and ground observations maintained by NOAA and NREL. Ground observations using one of the most common solar radiation measurement devices, a pyranometer, are extremely sensitive devices and can be inaccurate if installed or maintained incorrectly. This is especially true when only one location is used for measurement as opposed to a set of instruments across a wider area. Pyranometers require regular maintenance, cleaning and adjustments.[8] Without knowledge of how on the ground observations are done and the station maintenance it is impossible to know the causes behind discrepancies between KCHS observations and NSRDB data. Furthermore, due to the inherent difficulty in recording quality solar radiation data and maintaining observation sites, it is extremely important to review a large set of observation data. We recommend that if DESC seeks to conduct its own validation of NSRDB data it should select 10 or more sites with a significant period of measurements and compare against the same locations using NRELs SAM tool and NSRDB datasets.

Although we suggest that if DESC seeks to review NSRDB data itself it should cast a much wider net both geographically in South Carolina and for different weather years, we advise first to review validation studies conducted by NREL on the NSRDB. Significant work has been done to validate and test the accuracy of these models over the years and the following reports can benefit DESC in understanding why the NSRDB source may be the most convenient for forecasting output from large utility-scale PV operations while ensuring high quality data is used.[9]

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[8]ESS Earth Sciences, *Pyranometer Maintenance for Accurate Data*, 2020 https://www.essearth.com/pyranometer-maintenance-for-accurate-data/

[9] Evaluation of the National Solar Radiation Database (NSRDB Version 2): 1998-2015, https://www.nrel.gov/docs/fy17osti/67722.pdf

Validation of the National Solar Radiation Database (NSRDB) (2005-2012), https://www.nrel.gov/docs/fy15osti/64981.pdf

Validation of GOES-Derived Surface Radiation Using NOAA's Physical Retrieval Method, https://www.nrel.gov/docs/fy13osti/57442.pdf

Retirement Study

4. What additional TIA scenarios should DESC consider to inform future resource planning?

The TIA presented at the Stakeholder Session VI included five cases of replacement resources located at Jasper, Canadys, and Wateree. However, as discussed during the stakeholder session, there were notable omissions not evaluated in the TIA. We appreciate DESC's willingness to augment the TIA this year with additional scenarios and appreciate the ability to make recommendations.

<u>Scenario X, Local Replacement Resources in Charleston</u>: The TIA failed to analyze a scenario where replacement resources were located at or near the Williams station. Because the Charleston area is a load pocket on the transmission system, retiring a large amount of generation in the area without local replacement is likely to be a large driver of the transmission upgrade costs. DESC has already confirmed that substantive transmission upgrades are not required for Wateree retirement and would likely not be required if replacement resources were located at or near the existing Williams site. DESC should therefore include portfolios with full and partial replacement resources located in the load pocket. Standalone battery storage resources could be an effective mitigation for transmission upgrades.

<u>Scenario Y, Smaller Replacement Options at Canadys</u>: The TIA scenarios were evaluated with replacement resources located at Canadys due to existing transmission infrastructure originating from the site. To our knowledge Canadys was the site of a 490 MW coal generator, but most replacement resources evaluated at this location were larger than the previous coal plant (1057 MW in Case 3 and 534 MW in Case 4). It is unclear from the results how much of the network upgrade costs are attributed to the increased capacity sited at the location. An alternative scenario should evaluate a like-for-like capacity replacement of the 490 MW plant to avoid additional network upgrades.

<u>Scenario Z, Winyah replacement</u>: Lastly, a scenario that explicitly evaluates the proposed Winyah coal retirement in neighboring Santee Cooper region would also be incorporated. There may be either increased transmission costs or potential cost savings associated with interregional transmission planning.

2022 IRP Update

5. Do you recommend any changes to the new unit assumptions used in the 2021 IRP Update that DESC should consider as part of the 2022 IRP Update?

We are generally supportive of using the NREL ATB Advanced Technology Cost Scenario for solar and battery storage resources, provided it is updated to the latest available version. However, it is unclear from DESC's stakeholder session material what the source will be for thermal resources. The 2021 IRP used publicly available data sources, while the coal retirement Study includes assumptions "per DE Project Construction as informed by actual bids." More information is needed. In addition, we have the following recommendations:

Inflation and Supply Chain Adjustments: Given current macroeconomic conditions, inflationary pressure and supply chain constraints are likely across the industry in the short term. DESC should avoid applying any additional costs solely to renewable or storage resources. While these challenges have been a topic of concern across the industry, these disruptions will be true for conventional thermal technologies and transmission investment as well - including for replacement parts and plant upgrades.

Battery Energy Storage Operations: Charging constraints for solar investment tax credit (ITC) can be included, but DESC should avoid over-constraining the model. Specifically, the Paired Solar and Charging constraint that requires hybrid solar + storage facilities to charge the battery exclusively from the solar systems can be adjusted. It should be noted that this is a financial, rather than technical limitation on the technology and attributed to the solar investment tax credit ("ITC"). However, this tax credit has two notable stipulations to accommodate some level of grid charging. First is that the ITC is a five-year tax incentive. After the first five years of operation, the battery is free to charge from the grid if beneficial to the system operator. Second, the ITC allows for up to 25% of annual charging load to come from the grid before the tax incentive is lost. Any grid charging up to 25% reduces the ITC incentive proportionally (so 5% grid charging would reduce tax incentives by 5%). Therefore, while grid charging would incur a cost to the project owner, it could still be economic to grid charge sparingly during tight supply conditions. For example, a low-solar winter peak demand period could benefit from grid charging during off-peak hours to ensure the battery storage system is available during peak load. While compensation would need to be made to make the asset owner whole, the grid charging limitation should not be treated as a hard constraint.

PLEXOS has the option to make these constraints a "soft constraint," incurring an economic penalty to violate. We recommend including a PLEXOS parameter for "RHS Penalty" of $500/MWh for any grid charging (i.e. violation of the Paired Solar and Charging constraint). This will avoid grid charging unless it significantly reduces costs for ratepayers by avoiding load shed or reserve violations.

Heat Rates for CC and CT units: In Sierra Club's comments on the 2021 IRP Update, witness Derek Stenclik identified errors in the way CC and CT unit heat rates were modeled. Namely if the user defines an incremental heat rate curve, PLEXOS will, by default, calculate a third-order polynomial fit to the heat input function. This automatically adjusts the heat rate curve. In the case of the new ICT and CC generators, the Company's specific heat rate curve was not properly refit to the polynomial curve. To avoid this change – and use the Company's heat rate curve directly, the model's "Production object" setting for "Max Tranches" must be set to less than three so that the simulator used the marginal heat rate function provided in the input data verbatim.

We recommend that DESC provide detailed heat rate modeling assumptions for all units at the next stakeholder session.

Other Comments - Not Specifically Requested by DESC

6. Additional Requested Scenarios for Coal Retirement Study

Similar to the request for recommendations for new TIA scenarios, we also kindly propose a subset of coal retirement scenarios in PLEXOS. We believe these scenarios will allow for more transparent results to clearly show the changes to system cost, emissions, and operations with coal retirements.

- <u>Accelerated Retirements</u>: Similar to the proposed TIA scenario, we propose DESC evaluate a scenario that assumes an early retirement (12/31/2028 at the latest) for *both* Williams and Wateree. This is consistent with the 2021 IRP Update preferred portfolio RP8. This would allow Williams to avoid the substantial, 142M$ ELG upgrade and thus reduce the overall cost of the coal retirement scenarios considerably. The fact the Coal Retirement Study did not in fact evaluate timely coal retirements - as proposed by the IRP and ELG compliance schedules - is an egregious oversight. If DESC believes replacement resources cannot be online by the end of 2028 they should still provide the model results to quantify the impact to ratepayers.

  In addition, this scenario should not include transmission upgrades for the Williams retirement, on the assumption that replacement resources are located at or near the Williams site. Again, if DESC does not believe this is feasible, they should at least provide the model results and clearly explain why it is not feasible. Together the avoided ELG upgrades and transmission additions would reduce the cost of the coal retirement scenarios by 564 M$ (255M$ for the ELG upgrades at both Williams and Wateree and 309M$ for the transmission upgrades).

- <u>Low Load / High Energy Efficiency</u>: While the DESC proposed scenario matrix includes base and high load forecasts, a low load forecast scenario is not evaluated. Previous Sierra Club testimony shows that DESC has routinely overstated load growth. In addition, the growth rate in DESC's forecast is notably higher post 2030, presumably due to increased electrification, when the coal retirements would occur. If this load growth does not materialize as expected - or energy efficiency is higher than expected - there is a risk of stranded assets. As a result, we recommend a scenario that assumes lower load growth.

- <u>Clean Energy Only Replacement</u>: In addition, we propose scenarios (both PLEXOS LT and ST) that assume coal retirements and no new gas resources are available. This will properly bookend the analysis to show the costs, benefits, emissions, and operations with a clean energy replacement portfolio.

7. Modeling & Assumptions for Neighboring Balancing Areas

We maintain that interregional planning is essential and captures the benefits of load diversity, weather diversity, and resource diversity. DESC's current position is that "Including other Balancing Areas ("BA") in the resource adequacy study is only appropriate if a group of BAs is jointly responsible for reliability. DESC is solely responsible for resource adequacy within its BA. Reliability events often affect all neighboring utilities at the same time, and DESC has been unable to rely on neighboring BAs during past events."[10] However this is an overly restrictive assumption and not in line with industry best practice considered in neighboring utilities. It is not only important in resource adequacy studies, but also in production cost (ST) and capacity expansion (LT) modeling efforts.

The assumption that no energy is available for purchase during shortfall events would unnecessarily inflate the planning reserve margin. We reviewed historical hourly interchanges, as reported to EIA, and assumptions from neighboring utility resource adequacy analysis. In both practice and planning interchange between balancing areas is a normal assumption. The implementation of the Southeast Energy Exchange Market should only expand this opportunity.

Regarding analytical assumptions at nearby utilities, Georgia Power, Duke Energy Carolinas, and TVA resource adequacy studies were reviewed for their consideration of interchanges with neighboring systems. While each balancing authority in question states that neighboring energy can not always be relied on to satisfy shortfall events, they do not leave out modeling of their 1st tier (direct neighbor) systems from their reserve margin analysis. In fact, consideration of the probability of available energy from neighbors using robust stochastic analysis is a critical component of their resource adequacy and reserve margin planning. As per Duke Energy Carolina's 2020 IRP Resource Adequacy Study conducted by Astrape, the consideration of interconnected utilities ability to provide energy during shortfall events significantly lowers their planning reserve margin:

> "the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 19.25% which is 6.25% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one fourth of the 25.5% required reserves is reduced due to interconnection ties."[11]

Both Georgia Power and TVA also include language in their IRPs and Resource Adequacy studies that indicate consideration of neighboring utilities in their modeling and planning reserve margin calculations. For example, Georgia Power states that "[t]he SERVM model allows the System to account for expected support from neighboring regions based on historical load diversity and unit performance

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[10] DESC, Stakeholder Session VII, page 6.

[11] Astrape Consulting, *Duke Energy Progress 2020 Resource Adequacy Study*, 2020 https://dms.psc.sc.gov/Attachments/Matter/fbc46af8-82d2-4d44-856a-004f8e1bba65

diversity. Each weather year model uses the actual historical temperature and related load diversity for each region. The System is expected to buy power from neighboring regions that do not typically peak in the same hour as the System if those neighboring regions have capacity available to purchase."[12] In TVA, interchanges with neighboring utilities were modeled using historical purchases and sales being considered with respect to NERC LTRA Anticipated and Planning Reserve Margins (in addition to updates from utility IRPs). In Georgia Power, the reserve margins for neighboring regions are adjusted so they fall within a 0.1 LOLE threshold. This is to ensure that accounting for neighboring regions' own imports is accounted for in Georgia's modeling. Including modeling of neighboring regions to their own reserve margins or an LOLE of 0.1 days/year provides an adequate representation of how those neighboring regions will function and when available energy will be present on the system in the case of DESC shortfall events. It is important to note that all of the resource adequacy studies mentioned here use a stochastic approach to model several scenarios and sensitivities which provides meaningful insight into the likelihood of no energy being available from neighboring regions.

As a last point, we conducted a review of DESC's historical hourly demand and interchanges with neighboring utilities as far back as July 1, 2015 using EIA's Hourly Electric Grid Monitor.[13] Out of the 59,160 hours of data for DESC, 8,362 hours, approximately 14% of the time, DESC was a net importer of electricity. Taking a conservative view, net imports during hours where demand was above the 90th percentile (3,740 MW) were considered. Net imports reached up to 609 MW with an average of 135 MW. It is clear from historical data that given high load conditions, DESC has relied - at times - on imports of 100 MW or more. In fact, of the hours where demand is above the 90th percentile and DESC is a net importer, imports are greater than 100 MW 55% of the time and greater than 200 MW 21% of the time. Note that this historical view only looks at actual transactions. It does not consider times where surplus capacity was available, but not specifically requested.

We recommend DESC to consider implementing modeling of neighboring balancing authorities with consideration of their generation supply, load, LOLE and reserve margin targets. Ample public data is available for adequate modeling of neighbor's resources and a combined model allows for the benefits of diversity of load and diversity of resources to be understood using stochastic modeling of outages and generation.

[12] GA Power, *Georgia Power's 2022 Integrated Resource Plan*, 2021 https://psc.ga.gov/search/facts-docket/?docketId=44160

[13] EIA Hourly Electric Grid Monitor https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/SCEG

We appreciate the opportunity to participate in the stakeholder process and provide comments. Please do not hesitate to reach out to us if you have any questions.

Best Regards

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Exhibit DS-04

DESC Response to ORS 2-11

DOMINION ENERGY SOUTH CAROLINA, INC.
SOUTH CAROLINA OFFICE OF REGULATORY STAFF'S
SECOND AND CONTINUING EQUEST FOR PRODUCTION OF
BOOKS, RECORDS, AND OTHER INFORMATION
DOCKET NO. 2023-9-E

REQUEST NO. 2-11:

Refer to Company response to ORS IR #1-23. The Company states that, "Reasonable limits were chosen based on experience and engineering judgment" and a table was supplied in response to question c.

a. Please explain why the Company believes that no more than 2 solar units per year could be built.

b. Please explain how 20 was selected as the Max Units Built before 2036 for Solar IRA resources.

c. Please explain why there is a difference in the Max New Solar units that can be built between 2036 – 2050 (8 for Company owned, 28 for PPA). Explain how 8 and 28 were selected.

d. Please explain why the inputs for New Solar IRA and New Solar PPA IRA are identical, yet there were differences for the non-IRA generic resources. Also, explain why the 20 and 0 inputs for those resources were modeled.

e. Please explain why there were no Max Units Built per Year constraints modeled on New Batteries, but they were for solar?

f. Please provide the Company's historic interconnection rate of solar resources for the past 10 years.

g. Explain whether the same interconnection rate is expected to continue into the future, or whether it might be possible that the interconnection rate could increase in the future.

h. Given the model's selection of solar in an unbounded case discussed in part d of its response, did the Company consider increasing the modeled rate at which future projects could be added in future years? If not, please explain.

i. What barriers does the Company anticipate to the interconnection rate and project availability rates? Is the Company doing or will the Company do anything to try to mitigate the barriers to allow greater interconnection rates in the future? Please explain.

j. Please explain why 8 was the Max Units Built Limit on both New Battery85% and New Battery50% in the respective time periods that those limits apply.

k. The Company states that limits were selected for thermal resources. For each thermal resource, please provide the limits, and give a detailed explanation of how the specific values were determined.

DOMINION ENERGY SOUTH CAROLINA, INC.
SOUTH CAROLINA OFFICE OF REGULATORY STAFF'S
SECOND AND CONTINUING EQUEST FOR PRODUCTION OF
BOOKS, RECORDS, AND OTHER INFORMATION
DOCKET NO. 2023-9-E

<u>RESPONSE NO. 2-11:</u>

Save Your Files Here 2023 IRP – 2023-9-ESierra Club #11-03Basis for DESC IRP Solar Build Limitation 20220609 CONFIDENTIAL.xlsx

a. The Company does not intend to imply that two is the maximum number of stand-alone solar facilities that can be built in a year, but both industry consensus and DESC's research conclude that 5%-8% of peak hour load is a reasonable limit for the sustained pace of solar build over years and decades. For DESC this is about 300 MW-AC of solar panels and inverters per year and that conclusion is reasonable.
b. The IRA ITC and PTC schedule ramps down in 2033 and concludes by 2036 which is 10 years. Building at a rate of two 75 MW-AC IRA PPA resources per year over 10 years would result in 20 as the maximum number of build units.
c. Limiting the Max Units Built reduces the complexity of the problem by lowering the total number of choices available to the model. As long as the number available exceeds the number chosen or is equal to a side constraint such as Max Units Built per Year, the optimization can be more efficient and still optimize the build. DESC modelers observed that over the 14 years 2036 to 2050, PLEXOS built all Solar PPA units so the Max was set to 2 per year X 14 years = 28. They also saw that in early runs, fewer than 8 New Solar units were being built and capped that build to allow PLEXOS to solve each optimization more efficiently.
d. New Solar IRA and New Solar PPA IRA are not identical. PPA resources have a Use of Service [UoS] charge and a different WACC which are both consistent with the non-IRA resources. IRA resources can only be built through 2036. After 2036 only non-IRA resources can be built therefore the "Max Units Built in Year" for IRA resources is zero after 2036.
e. Using preliminary findings of the DESC Planning Reserve Margin Study along with the previous ELCC schedule and basis for that schedule, 1600 MW of batteries were included with a declining ELCC value roughly following the previous battery ELCC schedule. The basis was that batteries have less than 100% capacity value that declines as storage becomes a larger portion of total resources and most importantly, the forecast ELCC value drops rapidly at about 20% of system peak load. 1,600 MW of batteries combined with 576 MW of pumped storage goes well beyond 20% and no additional batteries need be considered for capacity value. With 1,600 MW of batteries available, PLEXOS does not try to build an unreasonable amount of storage in a single year and no annual limit is needed.
f. DESC Solar PPA by commercial operation date.

	MW Solar by COD
2015	0.5
2016	6.8
2017	211.33
2018	80.88
2019	260.89
2020	305.27
2021	22
2022	74.97

g. In any given year in the future the interconnection rate could be higher or lower. It is doubtful that the current rate will continue into the future but is likely to be on average 300 MW per year or less if the supply, demand, and pricing trends continue.
h. The Company does not believe that a rate in installation above 300 MW can be sustained in DESC's service territory and therefore, a higher rate should not be modeled.
i. First, the Company has not created any barriers to the adoption of solar in the service territory. The Federal Government has given solar every advantage within their power, reinstated and extended those benefits, and the adoption rates are still well under DESC modeling limits. The DESC modeling limit is not an explanatory variable or actual limit but does allow the PLEXOS model to create a better representation of the future.
j. Please see (e) above.
k. Thermal unit build limits are established in an iterative process and only represent a number that does not limit the optimization (at least one more than is built) but also limits the problem size so a better optimization can occur. DESC modelers observe how many thermal units are built and add a build limit that is one or two units higher.

PERSON RESPONSIBLE: Eric H. Bell

Exhibit DS-05

Sierra Club comments to IRP Stakeholder Session VIII

June 27, 2022

DESC Stakeholder Workshops

Session 8: 2022 IRP Update

Session 8 Homework: Jun 8, 2022

The answers to the Session 8 Homework questions were developed by Derek Stenclik and Ryan Deyoe of Telos Energy on behalf of the Sierra Club. Sierra Club appreciates this opportunity to provide feedback to the Session 8 Stakeholder Meeting. Engaging stakeholders early in the planning process creates a collaborative environment and ensures that modeling details and assumptions are properly vetted early in the process to allow ample time for revision before the final IRP study is conducted.

General Feedback

1. What topics should DESC add to the agenda for Session IX or as part of a future Stakeholder Session?

Sierra Club appreciates the ability to provide recommendations on future Stakeholder Sessions and believe the following topics would benefit from stakeholder input and discussion with DESC:

- <u>Additional TIA Study Results</u>: Please include a discussion of results from the additional TIA scenarios studied for Q3 2022 and how they will be incorporated into the 2022 IRP update and the 2023 IRP. If the study is not yet complete and stakeholders have not had a chance to review the scenarios assessed, a discussion should be included as part of Session IX since the Coal Retirement Study comments will already have been submitted on June 27, 2022.
- <u>Discussion of Annual Build Limits</u>: During Session VIII, DESC proposed annual build limits of 300 MW per year and 150 MW per year of solar and battery storage resources, respectively. Stakeholders expressed concern with DESCs choice to limit annual builds to

such a small amount as this could limit the ability for alternative resources to replace coal retirements. Please include a discussion of DESCs justification for annual build limits of solar and storage and provide sensitivity results if this constraint is relaxed (if available).

- <u>Resource Adequacy and ELCC Study</u>: We request additional discussion on the methods DESC plans to use to calculate the effective load carrying capability ("ELCC") (marginal versus average), and which resource types will be evaluated, and what methods will be used in the resource adequacy modeling.
- <u>Selection and Reasoning for Risk Metric Evaluation</u>: DESC provided a review of different risk metric strategies used by neighboring regions for evaluating resource portfolios. We ask that DESC provide which risk metric approach they will implement for future IRPs and a discussion on why other approaches were not chosen.

Modeling Approach

2. What other elements of the Coal Retirement Study, if any, should be carried forward into future IRPs?

There are 3 items from the Coal Retirement Study that should be carried forward into future IRPs:

a. **Accelerated Coal Retirements:** The coal retirement study clearly indicates that early retirement of the Wateree and Williams coal plants is cost effective and beneficial to customers under a majority of the retirement scenarios studied. This key finding should be carried forward into future IRPs as DESC plans for capacity replacements and conducts its future IRPs. Even if PLEXOS is used for optimal capacity expansion planning, we suggest that scenarios continue to be evaluated with earliest possible retirement dates for Wateree and Williams.

b. **Integrated Resource and Transmission Planning:** The information provided in the Transmission Impact Assessment ("TIA") is valuable for the IRP analysis. This type of coordination between resource planning and transmission planning is important for the IRP. While Sierra Club maintains that the TIA and Coal Retirement Study would benefit from additional analysis and strategic resource placement in the Charleston load pocket to avoid major transmission upgrades, the intent of the TIA and Coal Retirement Study are a net positive on DESCs planning process.

We suggest DESC go one step further and incorporate transmission constraints into their production cost modeling using either a nodal, or zonal (pipe and bubble) modeling approach. This setup in PLEXOS would be informed by a detailed transmission analysis where constraints like the simultaneous import limit into Charleston or import/export limits between neighboring regions could be captured and better reflect resource dispatch and constraints on DESCs system. The more accurately DESC can represent their system in production cost modeling, the better the resource dispatch and optimization will be.

c. **Economic Benefits of Replacement Resources:** An additional element from the Coal Retirement Study that we suggest DESC incorporate into future IRPs is the assessment of the economic benefits of different resource procurements. While the Coal Retirement Study provided a short description of the job benefits from construction and operation of natural gas and solar power plants, DESC should broaden their assessment of replacement resources to include property tax benefits, geographic distribution of benefits, health benefits due to reduced EPA criteria pollutants and differences in CO_2 emissions for resource classes (e.g. solar, storage, nuclear, natural gas, etc.). Including a broad assessment of the economic benefits from different resource types is important to show the opportunities presented by replacing older generation units with more advanced and clean technologies.

3. Do you agree with the approach of carrying forward RP8 from the 2021 IRP Update even though an optimization approach will be used in future IRPs?

We support the comments of the South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE") and Carolinas Clean Energy Business Alliance ("CCEBA") to this question. In addition, we agree with DESC that RP8, the preferred plan from the 2021 IRP Update, should be considered in future IRPs. DESC's optimal expansion planning using PLEXOS is a useful screening tool, but can be limited due to hardcoded assumptions or resource limitations embedded in the modeling. Specific scenarios should also be considered and assessed for NPVRR and analyzed using DESCs chosen risk metrics. We also suggest that DESC should consider portfolios R06 and R06b from Sierra Club's Coal Retirement Study comments, which consider an accelerated retirement of Williams in 2028 and a scenario that includes a standalone storage or other replacement resource located at or near the Williams site.

New Unit Assumptions

4. What additional resource types, if any, should DESC consider in the 2022 IRP Update and future IRPs?

We support the comments of CCL, SACE, and CCEBA to this question along with their detailed DSM and energy efficiency overview in section 9 of their comments as further reasoning for why we suggest higher levels of DSM and energy efficiency should be assessed as resource options.

In addition, Sierra Club recommends that DESC consider additional levels of energy efficiency and demand response, modeled as supply-side candidate resources that can be selected by the model. While DESC has stated they intend to assess whether higher levels of DSM (such as 2% as ordered by the Commission) are feasible, they should also assess whether PLEXOS' optimal expansion plan selects these resources in their analysis. As the electrification of load progresses, more devices will be connected and the potential for increased demand response from flexible load across multiple customer classes should be considered for peaking conditions or aggregate energy demand reductions.

5. Are the (forthcoming) cost & performance assumptions provided by DESC reasonable? What changes are needed?

Sierra Club appreciates DESC's continued use of the NREL ATB cost assumptions for their solar and storage candidate resources, including using the recently released 2022 ATB which provides DESC and stakeholders a transparent data source where all parties can review and understand the assumptions incorporated in the capital cost trends for different technologies.

In contrast, Sierra Club does not support the use of DESC's "Green Sheets" for thermal unit cost assumptions. While the 2022 IRP update cost assumptions are still forthcoming, historically, the assumptions used to determine the capital cost of thermal resources in the Green Sheets are vague and are difficult for stakeholders to verify against alternative thermal resource capital cost sources such as the U.S. EIA or NREL ATB. Sierra Club requests that DESC use a consistent set of transparent cost assumptions for candidate resources so drivers in cost reductions or increases are clear to stakeholders. If DESC would prefer to use actual bid data for capital cost assumptions, Sierra Club recommends using an all source procurement mechanism as suggested by DESC in the 2021 IRP Update and the CT Replacement plans.

For comparison, Table 1 below shows the changes in combustion turbine cost assumptions used by DESC from the original 2020 IRP, 2021 IRP and the recent Coal Retirement Study and their data source. Each of these capital cost assumptions presents significantly different costs, using combustion turbines as an example. We have included the EIA AEO 2022 CT capital cost as this most closely matches the updated capital cost assumptions DESC was required to implement for the 2021 IRP update. DESC's Green Sheets present capital costs 12% lower than the EIA AEO 2022 and 40% lower than the NREL 2022 ATB data. These are significant differences which require thorough explanation and justification.

Table 1: Comparison of DESC Combustion Turbine Capital Costs to Alternatives (2022 $/kW)

Report/Source	Resource	Capital Cost (2022 $/kW)[1]
DESC 2020 IRP - Green Sheets	ICT Frame J (2x)	505
DESC Coal Retirement - Green Sheets	Frame Combustion Turbine - Pair	658
2021 IRP Update - EIA AEO 2020	CT Large Frame (2x)	769
EIA AEO 2022	CT - Industrial Frame	745
NREL 2022 ATB	NG F-Frame CT	926

6. Are the (forthcoming) ELCC values for new storage resources reasonable? What changes are needed?

Yes, the suggested ELCC values for new storage resources are reasonable, provided they are used as temporary values before a more detailed resource adequacy, planning reserve margin, and ELCC study can be conducted. An alternative suggestion is to use the Coal Retirement Study hourly production cost results to approximate capacity credits. This can be done by calculating the average output of storage resources (and other technologies) during the tightest margin hours (i.e. lowest 2% of hours annually). This RA Hour metric is being considered by MISO in

[1] Capital costs were escalated from the sources reported dollar year to 2022 using DESC's stated 3.75% escalation rate.

their capacity accreditation redesign.[2] Calculating resource availability during low margin hours will likely track ELCC calculations closely and can be computed with limited effort.

Please note that these resource adequacy assessments are very important inputs to the IRP planning process and we would like additional information on the studies, methodologies, and assumptions being considered by DESC. While the Stakeholder Meetings have discussed the objective and timeline of these studies, it is important that stakeholders have input on key assumptions and methods, prior to the study being completed.

Finally, while it is important to consider the capacity accreditation (ELCC) of storage resources, similar attention should be given to solar, coal, gas, hydro, etc. There is no such thing as perfect capacity and accreditation methods should be applied to all resources. Natural gas generation, for example, can be limited during scarcity periods due to correlated outages during extreme weather, and fuel supply disruption.[3] Large thermal units can also disproportionately affect resource adequacy. As a result, similar methods for calculating ELCC should be applied to thermal resources as well.[4,5]

Similar to storage, we recognize that a placeholder value will be required until more in-depth analysis can be completed. Our recommendation for this temporary value is to use a thermal unit's capacity minus the equivalent forced outage rate as the firm capacity value. This unforced capacity method is used in PJM, NYISO, and MISO.[6] By not adjusting the firm capacity credit assigned to thermal resources overstates their capacity contributions for resource adequacy.

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[2] Midcontinent Independent System Operator, *Non-Thermal Accreditation Workshop,* June 21, 2022, https://www.misoenergy.org/stakeholder-engagement/committees/resource-adequacy-subcommittee/

[3] Astrape, *AEE Accrediting Resource Adequacy Value to Thermal Generation,* April 2022, https://www.astrape.com/?ddownload=9291

[4] Energy Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems,* https://www.esig.energy/resource-adequacy-for-modern-power-systems/

[5] American Council on Renewable Energy, Ensuring Low-Cost Reliability: Resource Adequacy Recommendations for a Clean Energy Grid, https://acore.org/resource-adequacy-report/

[6] The Brattle Group, *Capacity Resource Accreditation for New England's Clean Energy Transition, Foundations of Resource Adequacy,* June 2, 2022, https://www.mass.gov/doc/capacity-resource-accreditation-for-new-englands-clean-energy-transition-report/download

Market Scenarios

7. Are the proposed Market Scenarios for the 2022 IRP Update reasonable, what changes or additional scenarios do you suggest DESC consider in future IRPs?

Sierra Club appreciates the opportunity to suggest additional market scenarios for DESC to consider for future IRPs. With respect to the timeline required for DESC to implement new market scenarios, Sierra Club proposed three additional market scenarios which can be readily implemented using DESCs existing input assumptions. These scenarios are described in Table 2 with a description of what each scenario intends to represent. Overall, Sierra Club does not think the current proposed market scenarios reflect the risk of high fuel prices or low load growth scenarios.

Table 2: Proposed Additional IRP Market Scenarios

Scenario Name	Fuel Price	CO2 Price	Load	DSM	Notes
High fuel price and medium CO_2 price with smarter electrification	High	Medium	Low	High/ Cost Effective	Represents a future where domestic fuel resources lack supply side investment in coal and natural gas, and state and federal policies increase fuel prices. Electrification continues, but with commensurate efficiency improvements and demand side management.
Increased environmental regulation with Increased DSM development	High	High	Mid	2% DSM	A future where high fuel prices and a high CO_2 price push electrification to progress faster. Higher load growth coupled with less investment in conventional generation or retirement due to high costs prompts more aggressive development of DSM potential in the market. Increased technological advancements in aggregating customer load, EVs and industry incentives to save on energy presents higher DSM and EE use as a more cost-effective measure to curb energy demand and peak load versus building more capacity.
Supply side fuel commodity restrictions	High	Zero	Low	High/ Cost Effective	This scenario is a future where CO_2 price regulation is absent and load growth maintains historical levels and is relatively flat. High fuel prices persist due to supply side underinvestment due to capital shifting away from fossil fuels and the market factoring climate change risks into company valuations. Load growth remains low due to economic recession and high inflation which offsets growth due to electrification.

Risk Metrics

8. What risk metrics should DESC include in the 2022 IRP Update and future IRPs given the format of the outputs?

We support the response of CCL, SACE and CCEBA to this question. We have also provided a description of how DESC's risk metric analysis could be conducted and examples of inputs that would make sense to sample stochastically or build sensitivity scenarios around.

Sierra Club recommends that DESC should include risk metrics in line with a minimax regret score and the TVA monte carlo distribution method.[7] Combining these two approaches provides DESC with many scenario results based on the stochastic sampling of inputs with the benefit of a simple minimax regret score for each portfolio option across many scenarios. As described in the TVA example, the preferred portfolio may be the one that results in the most robust score and is resistant to extreme costs under the scenarios modeled. While the PLEXOS optimizations minimize total system cost, the IRP process is intended to identify the most *reasonable and prudent plan.* A more robust planning process - as required by Act 62 - is development of portfolios that consider economic efficiency but also limit ratepayer exposure to high risk.

For example, DESC could incorporate the following metrics to be sampled stochastically by PLEXOS or resolved as sensitivities in a spreadsheet analysis using the optimized PLEXOS portfolios.

- A range of capital cost assumptions to test robustness of chosen portfolio CapEx if assumed CapEx prices are higher or lower than input into the model.
- A wider range of natural gas and coal price forecasts to test for fuel price sensitivities
- A wider range of load forecasts to identify risks of building capacity for load that does not materialize
- A range of demand response forecasts and EV charging profiles

Note that the PLEXOS tool has these stochastic capabilities and can be used to evaluate the sensitivity of portfolio costs to uncertainty in assumptions. These inputs could be readily input into PLEXOS so many simulations can be run with different combinations of load, gas and capital cost assumptions and produce many portfolios for the minimax regret comparison.

[7] DESC IRP Stakeholder Advisory Group Meeting #8, June 18, 2022, at slides 50 and 51

Alternatively, DESC could select the optimized portfolios from their deterministic capacity expansion modeling under the DESC and stakeholder proposed market scenarios and then conduct a spreadsheet analysis of the robustness of each portfolio against a range of sensitivities that go beyond the small subset of market scenarios embedded in PLEXOS. The objective of this risk assessment isn't necessarily to only minimize costs or NPVRR, but also to minimize the worst-case outcome from a portfolio selection, which is consistent with the minimax approach.

We appreciate the opportunity to participate in the stakeholder process and provide comments. Please do not hesitate to reach out to us if you have any questions.

Best Regards

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Exhibit DS-06

DESC CONFIDENTIAL response to Sierra Club 1-3

Exhibit DS-07

DESC response to Sierra Club 3-3

DOMINION ENERGY SOUTH CAROLINA, INC.
SIERRA CLUB'S
SECOND SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 3-3:

Please explain why DESC does not allow the 50% firm capacity battery storage units to be built in the PLEXOS LT model until 2036+?

RESPONSE NO. 3-3:

The ELCC of the batteries drops to 50% once all of the 85% ELCC batteries have been built. Making the 50% batteries available after 2036 was the simplest way to accomplish this.

Exhibit DS-08

DESC response to ORS 1-55

DOMINION ENERGY SOUTH CAROLINA, INC.
SOUTH CAROLINA OFFICE OF REGULATORY STAFF'S
FIRST AND CONTINUING REQUEST FOR PRODUCTION OF
BOOKS, RECORDS, AND OTHER INFORMATION
DOCKET NO. 2023-9-E

REQUEST NO. 1-55:

Please provide 10 years of historic load data including summer peak demand, winter peak demand, and annual energy.

RESPONSE NO. 1-55:

See "Attachment to Response No. 1-55.xlsx" for historial calendar totals.

PERSON RESPONSIBLE: Bradley Perricelli, Joseph Stricklin

Energies				
Year	kWh			
2013	22,354,137,961			
2014	23,334,581,105			
2015	23,201,521,516			
2016	23,361,797,195			
2017	22,752,999,237			
2018	23,733,457,432			
2019	22,937,753,957			
2020	21,921,793,918			
2021	22,350,826,615			
2022	22,496,709,824			

Summer and Winter Peaks 2012 - 2022		
Year	**Season**	**MW**
2013	S	4,574
	W	3,984
2014	S	4,594
	W	4,853
2015	S	4,750
	W	4,970
2016	S	4,807
	W	4,409
2017	S	4,702
	W	4,457
2018	S	4,684
	W	4,756
2019	S	4,714
	W	4,198
2020	S	4,586
	W	4,087
2021	S	4,573
	W	4,221
2022	S	4,723
	W	4,678

Exhibit DS-09

DESC Response to Sierra Club 2-1

DOMINION ENERGY SOUTH CAROLINA, INC.
SIERRA CLUB'S
SECOND SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 2-1:

Please refer to the proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18824 (Mar. 29, 2023) (the "Proposed 2023 ELG Rule").

A. Does the Company anticipate incurring costs for retrofits at the Williams, Wateree and Cope coal units between now and 2032 to comply with the zero-discharge limitation for all pollutants in flue gas desulfurization (FGD) wastewater under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If no, please explain why not.

B. Does the Company anticipate incurring costs for retrofits at the Williams, Wateree and Cope coal units between now and 2032 to comply with the zero-discharge limitation for all pollutants in bottom ash transport water (BATW) under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If no, please explain why not.

C. Will the Proposed 2023 ELG rule require any capital expenditures at the Williams, Wateree and Cope coal units between now and 2032 to comply with the numeric discharge limitations for combustion residual leachate (CRL)? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If no, please explain why not.

RESPONSE NO. 2-1:

a. This is a proposed rulemaking activity; as such, the Company has not yet determined the scope and potential costs for any retrofits associated with the proposed rule to its facilities.
b. This is a proposed rulemaking activity; as such, the Company has not yet determined the scope and potential costs for any retrofits associated with the proposed rule to its facilities.
c. This is a proposed rulemaking activity; as such, the Company has not yet determined the scope and potential costs for any retrofits associated with the proposed rule to its facilities. The Company anticipates under EPA's proposed rule that CRL costs would be incurred regardless of when these generating units are retired and therefore are not relevant in the IRP proceeding.

Exhibit DS-10

CCL/SACE and Sierra Club CONFIDENTIAL comments submitted in response to DESC Stakeholder Session X

Exhibit DS-11

DESC response to Sierra Club 1-5

DOMINION ENERGY SOUTH CAROLINA, INC.
SIERRA CLUB'S
FIRST SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 1-5:

Regarding the generator heat rates provided in the PLEXOS input datafiles, please clarify whether the heat rates modeled are in Lower Heating Value (LHV) or Higher Heating Value (HHV), and whether they represent gross load or net load heat rates.

RESPONSE NO. 1-5:

The heat rates modeled are based on Lower Heating Value (LHV), and they represent gross load heat rates for new generation.

Exhibit DS-12

DESC response to Sierra Club 3-5

DOMINION ENERGY SOUTH CAROLINA, INC.
SIERRA CLUB'S
SECOND SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 3-5:

Refer to the Company's response to Sierra Club Request No. 1-5.

Please explain why DESC chose to model the combined cycle candidate resource options using a lower heating value (LHV) gross heat rate instead of a higher heating value (HHV) net heat rate?

a. Does DESC use LHV gross heat rates for all other thermal generators modeled, including the other candidate thermal resources?
b. Is the natural gas price modeled in the DESC model in LHV units or HHV units?

RESPONSE NO. 3-5:

DES Project Construction supplies the thermal generator specifications in the "Greensheets" in gross heat rates based on LHV.

a. No. New thermal resources use LHV and existing resources use HHV.

b. The natural gas price modeled in the DESC model is in HHV units.

Exhibit DS-13

DESC CONFIDENTIAL response to ORS 1-10

Exhibit DS-14

DESC response to Sierra Club 1-6

REQUEST NO. 1-6:

Reference DESC's comments in response to the Comments of Sierra Club on the 2022 IRP. DESC stated that "[t]o replace the energy and capacity that Williams provides to Charleston customers would require batteries capable of providing 600 MW of power for weeks or months at a time and would require them to be continuously recharged." Please explain the basis for this statement, specifically addressing:

A. Why sustained output of power for weeks or months at a time would be required from a battery storage system.
B. A detailed explanation of any analysis conducted by DESC to evaluate the potential for battery storage replacement at Williams or other locations within the Charleston area.
C. Workpapers, in native format with formulas intact, associated with any analysis conducted to validate this claim.

RESPONSE NO. 1-6:

A. Without some significant level of generation at Williams station or other location in the Charleston area with sustained output for weeks or months at a time, transmission upgrades will be required to ensure operational flexibility as well as compliance with NERC (North American Electric Reliability Corporation) Reliability Standards from a planning and operational perspective. DESC's experience operating the system is that it is difficult if not impossible to perform maintenance on transmission facilities in the Low Country when Williams is offline for scheduled maintenance or otherwise. Import capability from neighboring utilities is also often limited when Williams is offline. These operational restrictions may last for weeks or months in actual practice and will not be fully evident in the Transmision Planning studies which are performed for various snapshots of the state of the DESC system (and neighboring systems) for various peak conditions in their Transmission Impact Analyses.

B. DESC Transmission Planning has recently reported studies of three different battery storage system sizes at Williams station per the 2022 Transmission Impact Analysis study request (Cases 5A, 5B, 5C). The following battery storage system specifications were studied:

- 100 MW/400 MWH (part of Case 5A)
- 200 MW/800 MWH (part of Case 5B)

- 300 MW/1200 MWH (part of Case 5C)

The results of those studies found that, in a least cost scenario, a 100 MW battery system paired with the other generator replacement options described in Case 5A would require in total transmission upgrades of $332 million. Case 5B, which included a 200 MW battery system, would require $210 million in transmission upgrades. Case 5C, which included a 300 MW battery, would also require $210 million in transmission upgrades.

C. The final copy of the 2022 TIA Report which includes the analysis discussed in sub part b above, has been finalized by DESC Transmission Planning and is being reviewed, and will be submitted when completed.

Exhibit DS-15

DESC response to Sierra Club 3-4

DOMINION ENERGY SOUTH CAROLINA, INC.
SIERRA CLUB'S
SECOND SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 3-4:

Please explain why the FO&M cost for battery storage units (85% and 50% firm capacity) are different. Please provide workbooks that support these calculations with the formulas intact.

RESPONSE NO. 3-4:

The FO&M for the 85% batteries incorrectly used the cost of an 8hr battery instead of the 4hr battery. The FO&M for the 50% batteries correctly use 4hr battery cost. This will be corrected for the 2024 IRP Update.

Exhibit DS-16

Build Plan Tables

Alternative Plan - 2029 Coal Retirements Build Plan							
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Firm (MW)	New Solar (MW)	New Storage (MW)	Retirements (MW)
2023	4,902	6,305	28.6	0	0	0	0
2024	4,775	6,282	31.6	0	0	0	0
2025	4,813	6,277	30.4	0	0	0	0
2026	4,851	6,331	30.5	0	750	0	0
2027	4,891	6,345	29.7	0	750	0	0
2028	4,931	6,363	29.1	0	750	0	0
2029	4,971	5,972	20.1	0	600	1,000	-1,294
2030	5,009	6,048	20.7	0	600	100	0
2031	5,048	6,072	20.3	0	600	0	0
2032	5,091	6,139	20.6	0	600	100	0
2033	5,133	6,165	20.1	0	600	100	0
2034	5,179	6,674	28.9	0	600	700	0
2035	5,228	6,682	27.8	0	600	0	0
2036	5,274	6,687	26.8	0	600	0	0
2037	5,332	6,689	25.5	0	0	0	0
2038	5,390	6,554	21.6	0	0	0	0
2039	5,450	6,554	20.3	0	0	0	0
2040	5,509	7,074	28.4	523	0	0	0
2041	5,571	7,072	26.9	0	0	0	0
2042	5,633	7,073	25.6	0	0	0	0
2043	5,697	7,073	24.2	0	150	0	0
2044	5,761	7,075	22.8	0	225	0	0
2045	5,826	7,076	21.5	0	0	0	0
2046	5,892	7,078	20.1	0	0	0	0
2047	5,959	7,180	20.5	0	75	100	0
2048	6,026	7,443	23.5	262	0	0	0
2049	6,094	7,444	22.2	0	0	0	0
2050	6,163	7,445	20.8	0	0	0	0

Alternative Plan - 2031 Coal Retirements Build Plan							
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Firm (MW)	New Solar (MW)	New Storage (MW)	Retirements (MW)
2023	4,902	6,305	28.6	0	0	0	0
2024	4,775	6,282	31.6	0	0	0	0
2025	4,813	6,277	30.4	0	0	0	0
2026	4,851	6,331	30.5	0	600	0	0
2027	4,891	6,343	29.7	0	600	0	0
2028	4,931	6,361	29.0	0	600	0	0
2029	4,971	6,005	20.8	0	600	400	-684
2030	5,009	6,031	20.4	0	600	0	0
2031	5,048	6,070	20.2	0	600	700	-610
2032	5,091	6,137	20.6	0	600	100	0
2033	5,133	6,213	21.0	0	600	100	0
2034	5,179	6,672	28.8	0	600	600	0
2035	5,228	6,679	27.8	0	600	0	0
2036	5,274	6,685	26.8	0	600	0	0
2037	5,332	6,687	25.4	0	0	0	0
2038	5,390	6,552	21.6	0	0	0	0
2039	5,450	6,552	20.2	0	0	0	0
2040	5,509	7,072	28.4	523	0	0	0
2041	5,571	7,071	26.9	0	300	0	0
2042	5,633	7,072	25.5	0	0	0	0
2043	5,697	7,072	24.1	0	0	0	0
2044	5,761	7,073	22.8	0	0	0	0
2045	5,826	7,077	21.5	0	600	0	0
2046	5,892	7,079	20.1	0	0	0	0
2047	5,959	7,180	20.5	0	0	200	0
2048	6,026	7,443	23.5	262	0	0	0
2049	6,094	7,444	22.2	0	0	0	0
2050	6,163	7,445	20.8	0	0	0	0

Alternative Plan - 2029 Coal Retirements, Enhanced Reliability Build Plan							
Year	Peak (MW)	Firm Capacity (MW)	Winter Reserve Margin (%)	New Firm (MW)	New Solar (MW)	New Storage (MW)	Retirements (MW)
2023	4,902	6,305	28.6	0	0	0	0
2024	4,771	6,282	31.6	0	0	0	0
2025	4,798	6,277	30.4	0	0	0	0
2026	4,821	6,331	30.5	0	750	0	0
2027	4,838	6,345	29.7	0	750	0	0
2028	4,855	6,363	29.0	0	750	0	0
2029	4,890	6,032	21.4	0	600	1,000	-1,294
2030	4,894	6,143	22.6	0	600	100	0
2031	4,910	6,167	22.2	0	600	0	0
2032	4,936	6,269	23.1	0	600	100	0
2033	4,954	6,330	23.3	0	600	100	0
2034	5,027	6,874	32.7	0	600	700	0
2035	5,051	6,882	31.6	0	600	0	0
2036	5,051	6,887	30.6	0	600	0	0
2037	5,091	6,889	29.2	0	0	0	0
2038	5,126	6,754	25.3	0	0	0	0
2039	5,173	6,754	23.9	0	0	0	0
2040	5,297	7,274	32.0	523	0	0	0
2041	5,300	7,272	30.5	0	0	0	0
2042	5,360	7,273	29.1	0	0	0	0
2043	5,433	7,273	27.7	0	75	0	0
2044	5,493	7,275	26.3	0	0	0	0
2045	5,631	7,276	24.9	0	300	0	0
2046	5,679	7,278	23.5	0	75	0	0
2047	5,707	7,380	23.8	0	0	100	0
2048	5,771	7,643	26.8	262	0	0	0
2049	5,840	7,644	25.4	0	0	0	0
2050	5,908	7,645	24.0	0	0	0	0

Exhibit DS-17

DESC response to SACE/CCL 1-4

DOMINION ENERGY SOUTH CAROLINA, INC.
CCL SACE'S
FIRST SET OF DATA REQUESTS
DOCKET NO. 2023-9-E

REQUEST NO. 1-4:

At page 12 of the 2023 IRP, DESC states "In the early morning of December 24, 2022, DESC lost generation resources at various times due to factors that in some cases were related to the weather directly and in others were not. Support was not available from neighboring utilities who were engaged in load shedding or otherwise in an emergency posture at that time. To maintain operating reserves, DESC was required to curtail firm off-system sales, impose voltage limitations, and impose a brief curtailment of firm load on the morning of December 24, 2022."

a. For each hour from December 22, 2022 to December 31, 2022 please provide DESC's available generating capacity by unit.

b. For each hour from December 22, 2022 to December 31, 2022 please provide the GADS cause code for each of DESC's generating units.

c. For each hour from December 22, 2022 to December 31, 2022 please provide the level of firm load curtailment.

d. For each hour from December 22, 2022 to December 31, 2022 please indicate which DESC units were not available due to lack of natural gas fuel supply.

RESPONSE NO. 1-4:

a. The Company will provide this information by April 11, 2023.

b. The Company will provide this information by April 11, 2023.

c. On December 24, DESC curtailed 94.7 MW of load beginning at 8:00 am. This load was able to be picked back up within a few minutes and was restored by 8:09 am. There was no other firm load shed for the period in question.

d. No units were unavailable due to lack of natural gas fuel supply for the period in question.

UPDATED RESPONSE NO. 1-4:

a. Please see attached Excel spreadsheet "CCL SACE Request 1-4a.xlsx".

b. Please see attached Excel spreadsheet "CCL SACE Request 1-4b.xlsx". DESC inteprets this question regarding units that were unavailable or limited during the time period in question; the attached response provides the GADS cause code for all forced outages and derates and maintenance outages and derates for the period in question. Please note that only the units that report to NERC GADS are included in this response (*i.e.,* greater than 20 MW nameplate rating).

CCL SACE Request 1-4a

Date and Time	Jasper 1 Value (MW)	Jasper2 Value (MW)	Jasper3 Value (MW)	Jasper4 Value (MW)	CEC 1 Value (MW)
12/22/2022 0:00	184	190	185	405	169
12/22/2022 1:00	184	190	185	405	169
12/22/2022 2:00	184	190	185	405	169
12/22/2022 3:00	184	190	185	405	169
12/22/2022 4:00	184	190	185	405	169
12/22/2022 5:00	184	190	185	405	169
12/22/2022 6:00	184	190	185	405	169
12/22/2022 7:00	184	190	185	405	169
12/22/2022 8:00	184	190	185	405	169
12/22/2022 9:00	184	190	185	405	169
12/22/2022 10:00	184	190	185	405	169
12/22/2022 11:00	184	190	185	405	169
12/22/2022 12:00	184	190	185	405	169
12/22/2022 13:00	184	190	185	405	169
12/22/2022 14:00	184	190	185	405	169
12/22/2022 15:00	184	190	185	405	169
12/22/2022 16:00	184	190	185	405	169
12/22/2022 17:00	184	190	185	405	169
12/22/2022 18:00	184	190	185	405	169
12/22/2022 19:00	184	190	185	405	169
12/22/2022 20:00	184	190	185	405	169
12/22/2022 21:00	184	190	185	405	169
12/22/2022 22:00	184	190	185	405	169
12/22/2022 23:00	184	190	185	405	169
12/23/2022 0:00	184	190	185	405	169
12/23/2022 1:00	184	190	185	405	169
12/23/2022 2:00	184	190	185	405	169
12/23/2022 3:00	184	190	185	405	169
12/23/2022 4:00	184	190	185	405	169
12/23/2022 5:00	184	190	185	405	169
12/23/2022 6:00	184	190	185	405	169
12/23/2022 7:00	184	190	185	405	169
12/23/2022 8:00	184	190	185	405	169
12/23/2022 9:00	184	190	185	405	169
12/23/2022 10:00	184	190	185	405	169
12/23/2022 11:00	184	190	185	405	169
12/23/2022 12:00	184	190	185	405	169
12/23/2022 13:00	184	190	185	405	169
12/23/2022 14:00	184	190	185	405	169
12/23/2022 15:00	184	190	185	405	169
12/23/2022 16:00	184	190	185	405	169
12/23/2022 17:00	184	190	185	405	169
12/23/2022 18:00	184	190	185	405	169
12/23/2022 19:00	184	190	185	405	169
12/23/2022 20:00	184	190	185	405	169

12/23/2022 21:00	184	190	185	405	169
12/23/2022 22:00	184	190	185	405	169
12/23/2022 23:00	184	190	185	405	169
12/24/2022 0:00	184	190	185	405	169
12/24/2022 1:00	184	190	185	405	169
12/24/2022 2:00	184	190	185	405	169
12/24/2022 3:00	184	190	185	405	169
12/24/2022 4:00	184	190	185	405	75
12/24/2022 5:00	184	190	185	405	**0**
12/24/2022 6:00	184	190	185	405	**0**
12/24/2022 7:00	184	190	185	405	**0**
12/24/2022 8:00	184	190	185	405	**0**
12/24/2022 9:00	184	190	185	405	**0**
12/24/2022 10:00	184	190	185	405	**0**
12/24/2022 11:00	184	190	185	405	**0**
12/24/2022 12:00	184	190	185	405	**0**
12/24/2022 13:00	184	190	185	405	**0**
12/24/2022 14:00	184	190	185	405	**0**
12/24/2022 15:00	184	190	185	405	**0**
12/24/2022 16:00	184	190	185	405	**0**
12/24/2022 17:00	184	190	185	405	**0**
12/24/2022 18:00	184	190	185	405	**0**
12/24/2022 19:00	184	190	185	405	84
12/24/2022 20:00	184	190	185	405	100
12/24/2022 21:00	184	190	185	405	100
12/24/2022 22:00	184	190	185	405	100
12/24/2022 23:00	184	190	185	405	102
12/25/2022 0:00	184	190	185	405	133
12/25/2022 1:00	184	190	185	405	141
12/25/2022 2:00	184	190	185	405	140
12/25/2022 3:00	184	190	185	405	140
12/25/2022 4:00	184	190	185	405	140
12/25/2022 5:00	184	190	185	405	140
12/25/2022 6:00	184	190	185	405	140
12/25/2022 7:00	184	190	185	405	140
12/25/2022 8:00	184	190	185	405	140
12/25/2022 9:00	184	190	185	405	140
12/25/2022 10:00	184	190	185	405	140
12/25/2022 11:00	184	190	185	405	140
12/25/2022 12:00	184	190	185	405	140
12/25/2022 13:00	184	190	185	405	140
12/25/2022 14:00	78	98	99	196	140
12/25/2022 15:00	**0**	99	100	129	140
12/25/2022 16:00	**0**	112	112	135	140
12/25/2022 17:00	38	128	127	159	140
12/25/2022 18:00	184	190	185	405	140
12/25/2022 19:00	184	190	185	405	140

12/25/2022 20:00	184	190	185	405	169
12/25/2022 21:00	184	190	185	405	169
12/25/2022 22:00	184	190	185	405	169
12/25/2022 23:00	184	190	185	405	169
12/26/2022 0:00	184	190	185	405	169
12/26/2022 1:00	184	190	185	405	169
12/26/2022 2:00	184	190	185	405	169
12/26/2022 3:00	184	190	185	405	169
12/26/2022 4:00	184	190	185	405	169
12/26/2022 5:00	184	190	185	405	169
12/26/2022 6:00	184	190	185	405	169
12/26/2022 7:00	184	190	185	405	169
12/26/2022 8:00	96	96	96	200	169
12/26/2022 9:00	**0**	107	107	131	169
12/26/2022 10:00	**0**	123	123	142	169
12/26/2022 11:00	**0**	124	123	141	169
12/26/2022 12:00	**0**	116	116	137	169
12/26/2022 13:00	**0**	109	109	133	169
12/26/2022 14:00	**0**	109	109	133	169
12/26/2022 15:00	**0**	117	117	138	169
12/26/2022 16:00	22	145	145	149	169
12/26/2022 17:00	184	190	185	405	169
12/26/2022 18:00	184	190	185	405	169
12/26/2022 19:00	184	190	185	405	169
12/26/2022 20:00	184	190	185	405	169
12/26/2022 21:00	**0**	190	173	158	169
12/26/2022 22:00	**0**	190	173	158	169
12/26/2022 23:00	**0**	190	174	159	169
12/27/2022 0:00	**0**	190	174	158	169
12/27/2022 1:00	54	190	137	172	169
12/27/2022 2:00	184	190	185	405	169
12/27/2022 3:00	184	190	185	405	169
12/27/2022 4:00	184	190	185	405	169
12/27/2022 5:00	184	190	185	405	169
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12/27/2022 8:00	184	190	185	405	169
12/27/2022 9:00	184	190	185	405	169
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12/27/2022 12:00	184	190	185	405	169
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12/27/2022 15:00	184	190	185	405	169
12/27/2022 16:00	184	190	185	405	169
12/27/2022 17:00	184	190	185	405	169
12/27/2022 18:00	184	190	185	405	169

12/27/2022 19:00	184	190	185	405	169
12/27/2022 20:00	184	190	185	405	169
12/27/2022 21:00	184	190	185	405	169
12/27/2022 22:00	184	190	185	405	169
12/27/2022 23:00	184	190	185	405	169
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12/29/2022 16:00	184	190	185	405	169
12/29/2022 17:00	184	190	185	405	169

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12/29/2022 20:00	184	190	185	405	169
12/29/2022 21:00	184	190	185	405	169
12/29/2022 22:00	184	190	185	405	169
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12/30/2022 18:00	184	190	185	405	169
12/30/2022 19:00	184	190	185	405	169
12/30/2022 20:00	184	190	185	405	169
12/30/2022 21:00	184	190	185	405	169
12/30/2022 22:00	184	190	185	405	169
12/30/2022 23:00	184	190	185	405	169
12/31/2022 0:00	184	190	185	405	169
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12/31/2022 5:00	184	190	185	405	169
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12/31/2022 7:00	184	190	185	405	169
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12/31/2022 10:00	184	190	185	405	169
12/31/2022 11:00	184	190	185	405	169
12/31/2022 12:00	184	190	185	405	169
12/31/2022 13:00	184	190	185	405	169
12/31/2022 14:00	184	190	185	405	169
12/31/2022 15:00	184	190	185	405	169
12/31/2022 16:00	184	190	185	405	169

12/31/2022 17:00	184	190	185	405	169
12/31/2022 18:00	184	190	185	405	169
12/31/2022 19:00	184	190	185	405	169
12/31/2022 20:00	184	190	185	405	169
12/31/2022 21:00	184	190	185	405	169
12/31/2022 22:00	184	190	185	405	169
12/31/2022 23:00	184	190	185	405	169
1/1/2023 0:00	184	190	185	405	169

CEC 2 Value (MW)	CEC 3 ST Value (MW)	MCM 1 Value (MW)	MCM 2 Value (MW)	VCS Value (MW)	URQ 1 Value (MW)	URQ 2 Value (MW)
169	248	125	125	662	65	66
169	248	125	125	662	65	66
169	248	125	125	662	65	66
169	248	125	125	662	65	66
169	248	125	125	662	65	66
169	248	125	125	662	65	66
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169	248	125	125	661	65	0
95	38	125	125	661	65	0
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0	0	125	125	661	65	1
0	0	125	125	661	65	25
0	0	125	125	661	65	55
0	0	125	125	661	65	55
0	0	125	125	661	65	55
0	0	125	125	661	65	55
0	0	125	125	661	65	55
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2	59	125	125	661	65	0
15	61	125	125	661	65	0

169	248	125	125	661	65	0
169	248	125	125	661	65	0
169	248	125	125	661	65	0
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URQ 3 Value (MW)	URQ 5 Value (MW)	URQ 6 Value (MW)	AM WMS Value (MW)	WAT 1 Value (MW)	WAT 2 Value (MW)	COPE Value (MW)
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FFPS 1 Value (MW)	FFPS 2 Value (MW)	FFPS 3 Value (MW)	FFPS 4 Value (MW)	FFPS 5 Value (MW)	FFPS 6 Value (MW)	FFPS 7 Value (MW)
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FFPS 8 Value (MW)	SALUDA 1 Value (MW)	SALUDA 2 Value (MW)	SALUDA 3 Value (MW)	SALUDA 4 Value (MW)	SALUDA 5 Value (MW)	PARR IC1 Value (MW)
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72	30	29	25	29	60	17

PARR IC2 Value (MW)	COIT 1 Value (MW)	COIT 2 Value (MW)	HAG 4 Value (MW)	HAG 5 Value (MW)	HAG 6 Value (MW)	URQ IC1 Value (MW)
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39	**0**	18	95	21	21	16
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0	**0**	18	95	21	21	16
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39	**0**	18	95	21	21	16
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39	18	18	95	21	21	16
39	18	18	95	21	21	16

URQ IC2 Value (MW)	URQ IC3 Value (MW)	URQ IC4 Value (MW)	NEAL SHOALS Value (MW)	PARR HYD Value (MW)	STEV CREEK HYD Value (MW)
17	0	49	0	6	7
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17	0	49	0	5	8
17	0	49	0	5	3
17	0	49	0	4	5
17	0	49	0	2	6
17	0	49	0	4	6
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CCL SACE Request 1-4b

	Started	Completed	Type	Cause Code
Williams Unit:1	12/14/2022 2:55:00 PM	12/30/2022 5:45:00 PM	Forced Derate	3410
Hagood - GT 6	12/23/2022 8:51:00 PM	12/23/2022 9:25:00 PM	Forced Outage	5130
Urquhart Unit:2	12/24/2022 12:50:00 AM	12/24/2022 3:42:00 PM	Forced Outage	1900
Urquhart Unit:6	12/24/2022 12:50:00 AM	12/24/2022 10:38:00 AM	Forced Outage	5047
Columbia Energy Unit:3	12/24/2022 4:14:00 AM	12/24/2022 9:46:00 PM	Forced Outage	4291
Columbia Energy Unit:1	12/24/2022 4:29:00 AM	12/24/2022 5:45:00 PM	Forced Outage	1799
Columbia Energy Unit:2	12/24/2022 4:48:00 AM	12/24/2022 1:06:00 PM	Forced Outage	1799
Wateree Unit:2	12/24/2022 9:00:00 AM	12/24/2022 3:16:00 PM	Forced Outage	3499
Parr - GT 3	12/24/2022 10:31:00 AM	12/31/2022 11:59:59 PM	Forced Outage	5246
Urquhart Unit:6	12/24/2022 12:23:00 PM	12/24/2022 1:14:00 PM	Forced Outage	5049
Urquhart Unit:6	12/24/2022 2:09:00 PM	12/24/2022 3:00:00 PM	Forced Outage	5049
Columbia Energy Unit:2	12/24/2022 2:18:00 PM	12/25/2022 6:46:00 PM	Forced Outage	801
Columbia Energy Unit:3	12/24/2022 9:46:00 PM	12/25/2022 6:46:00 PM	Forced Derate	801
Wateree Unit:1	12/24/2022 10:07:00 PM	12/28/2022 1:48:00 PM	Forced Outage	1050
Hagood - GT 4	12/25/2022 3:30:00 AM	12/25/2022 4:51:00 AM	Forced Outage	5250
Urquhart Unit:2	12/25/2022 1:40:00 PM	12/26/2022 3:57:00 PM	Forced Outage	4309
Jasper Unit:4	12/25/2022 3:00:00 PM	12/25/2022 5:16:00 PM	Forced Derate	5047
Jasper Unit:1	12/25/2022 3:00:00 PM	12/25/2022 5:16:00 PM	Forced Outage	5047
Urquhart Unit:6	12/25/2022 4:20:00 PM	12/26/2022 1:20:00 PM	Forced Outage	4311
Saluda - HY 5	12/26/2022 7:00:00 AM	12/31/2022 11:59:59 PM	Forced Derate	4535
Jasper Unit:4	12/26/2022 8:52:00 AM	12/26/2022 4:01:00 PM	Maintenance Derate	5047
Jasper Unit:1	12/26/2022 8:52:00 AM	12/26/2022 4:01:00 PM	Maintenance Outage	5047
Jasper Unit:4	12/26/2022 4:01:00 PM	12/27/2022 1:05:00 AM	Forced Derate	5049
Jasper Unit:1	12/26/2022 4:01:00 PM	12/27/2022 1:05:00 AM	Forced Outage	5049
Saluda - HY 4	12/27/2022 7:00:00 AM	12/31/2022 11:59:59 PM	Forced Derate	4535
Fairfield Unit:3	12/28/2022 5:00:00 PM	12/28/2022 8:20:00 PM	Forced Outage	4650
Fairfield Unit:4	12/28/2022 5:00:00 PM	12/28/2022 8:20:00 PM	Forced Outage	4650
McMeekin Unit:1	12/30/2022 9:30:00 AM	12/31/2022 11:59:59 PM	Maintenance Outage	3344
Williams Unit:1	12/30/2022 5:45:00 PM	12/31/2022 11:59:59 PM	Maintenance Outage	3410

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2023-9-E

In re: Dominion Energy South Carolina, Incorporated's 2023 Integrated Resource Plan (IRP)	**CERTIFICATE OF SERVICE**

I hereby certify that I have served the persons listed on the official service list for Docket No. 2023-9-E, listed below, a copy of the public version of Joint Direct Testimony of Derek P. Stenclik, along with accompanying exhibits, on behalf of Sierra Club, South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy via electronic mail on this day, June 27, 2023.

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Respectfully submitted this 27th day of June 2023.

_________________ on behalf of

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